No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. *Copies of the documents incorporated herein by reference may be obtained on request without charge from the Secretary of the Corporation at Suite 1201, 139 Water Street, St. John's, Newfoundland and Labrador A1B 3T2 (telephone (709) 737-2800) and are also available electronically at www.sedar.com. The securities being offered under this short form prospectus have not been and will not be registered under the United States Securities Act of 1933, as amended (the "1933 Act"), or any state securities laws, and may not be offered or sold within the United States or to, or for the account or benefit of, U.S. persons (as defined in Regulation S under the 1933 Act) unless the securities are registered under the 1933 Act or an exemption from the registration requirements of the 1933 Act and applicable U.S. state securities laws is available. See "Plan of Distribution".*

Secondary Offering **December 20, 2013**

SHORT FORM PROSPECTUS

FORTIS INC.

$1,594,000,000
4.00% Convertible Unsecured Subordinated Debentures represented by Instalment Receipts

The 4.00% convertible unsecured subordinated debentures (the "Debentures") of Fortis Inc. ("Fortis" or the "Corporation") offered hereby (the "Offering") will be sold by FortisUS Holdings Nova Scotia Limited (the "Selling Debentureholder"), a direct wholly owned subsidiary of Fortis, on an instalment basis at a price of $1,000 per Debenture. See "Details of the Offering — The Selling Debentureholder". Prior to full payment, beneficial ownership of the Debentures will be represented by instalment receipts (the "Instalment Receipts"). The first instalment of $333 is payable on the closing of this Offering. The final instalment of $667 is payable following notification to holders (the "Final Instalment Notice") that: (i) the Corporation has received all regulatory and governmental approvals required to finalize the acquisition (the "Acquisition") by an indirect wholly owned subsidiary of the Corporation of all of the issued and outstanding shares of UNS Energy Corporation ("UNS Energy"), an Arizona regulated utilities holding company whose common stock is listed on the New York Stock Exchange ("NYSE"); and (ii) the Corporation and UNS Energy have fulfilled or waived all other outstanding conditions precedent to closing the Acquisition, other than those which by their nature cannot be satisfied until the closing of the Acquisition (collectively, the "Approval Conditions"), as itemized in the agreement and plan of merger dated December 11, 2013 among Fortis, certain subsidiaries of Fortis and UNS Energy (the "Acquisition Agreement"). See "The Acquisition" and "The Acquisition Agreement". The Final Instalment Notice will set a date for payment of the final instalment (the "Final Instalment Date"), which shall not be less than 15 days nor more than 90 days following the date of such notice. **If a holder of an Instalment Receipt does not pay the final instalment on or before the Final Instalment Date, the Debentures represented by such Instalment Receipt may, at the option of the Selling Debentureholder, upon compliance with applicable law and the terms of the Instalment Receipt Agreement (as defined under "Details of the Offering — Instalment Receipts"), be forfeited to the Selling Debentureholder in full satisfaction of the holder's obligations or such Debentures may be sold and the holder will remain liable for any deficiency in the proceeds of such sale.** See "Details of the Offering".

The Corporation and the Selling Debentureholder have entered into subscription agreements dated December 11, 2013 pursuant to which certain institutional investors (each a "Private Placement Subscriber") will purchase on an instalment and private placement basis, in the aggregate, $206,000,000 principal amount of Debentures represented by Instalment Receipts (the "Private Placement Debentures") at a price of $1,000 per $1,000 principal amount of Private Placement Debentures for aggregate gross proceeds to the Selling Debentureholder of $206,000,000 (the "Concurrent Private Placement"). The closing of the Concurrent Private Placement is scheduled to occur on the Closing Date and is subject to the concurrent closing of the Offering. See "Financing the Acquisition — Concurrent Private Placement".

The holders of Debentures will be entitled to interest at an annual rate of 4.00% per $1,000 principal amount of Debentures, payable quarterly in arrears in equal instalments on the first business day of March, June, September and December of each year to and including the Final Instalment Date. The first interest payment will be made on March 3, 2014 in the amount of $5.5890 per $1,000 principal amount of Debentures and will include interest payable from and including the closing date of the Offering, which is expected to take place on or about January 9, 2014 (the "Closing Date"). Subsequently, quarterly interest payments will be made in the amount of $10.00 per $1,000 principal amount of Debentures. **On the day following the Final Instalment Date, the interest rate payable on the Debentures will fall to an annual rate of 0% and interest will cease to accrue on the Debentures.** Based on a first instalment of $333 per $1,000 principal amount of Debentures, the effective annual yield to and including the Final Instalment Date is 12.00%, and the effective annual yield thereafter is 0%.

If the Final Instalment Date occurs on a day that is prior to the first anniversary of the Closing Date, holders of Debentures who have paid the final instalment on or before the Final Instalment Date will be entitled to receive, on the business day following the Final Instalment Date, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the Closing Date had the Debentures remained outstanding and continued to accrue interest until such date (the "Make-Whole Payment"). No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the Closing Date.

Conversion Privilege

At the option of the holder and provided that payment of the final instalment has been made, each Debenture will be convertible into common shares of Fortis ("Common Shares") on or at any time after the Final Instalment Date, but prior to the earlier of the date that the Corporation redeems the Debentures or the Maturity Date (as defined below). The conversion price will be $30.72 per Common Share (the "Conversion Price"), being a conversion rate of 32.5521 Common Shares per $1,000 principal amount of Debentures, subject to adjustment in certain events. **A holder of Debentures who does not exercise its conversion privilege concurrently with the payment of the final instalment in order to convert its Debentures to Common Shares on the Final Instalment Date will hold a Debenture that pays 0% interest and may be redeemed by the Corporation in whole or in part on any trading day following the Final Instalment Date at a price equal to its principal amount plus any unpaid interest which accrued prior to the Final Instalment Date.** See "Details of the Offering".

The Debentures may not be redeemed by the Corporation except that the Debentures will be redeemed by the Corporation at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the Approval Conditions will not be satisfied; (ii) termination of the Acquisition Agreement; and (iii) July 2, 2015 if the Final Instalment Notice has not been given on or before June 30, 2015. Upon any such redemption, the Corporation will pay for each Debenture: (i) $333 plus accrued and unpaid interest to the holder of the Instalment Receipt; and (ii) $667 to the Selling Debentureholder on behalf of the holder of the Instalment Receipt in satisfaction of the final instalment. Under the terms of the Instalment Receipt Agreement, Fortis has agreed that until such time as the Debentures have been redeemed in accordance with the foregoing or the Final Instalment Date has occurred, the Corporation will at all times maintain availability under its revolving credit facility of not less than $600,000,000 to cover one-third of the principal amount of the Debentures in the event of a mandatory redemption. See "Details of the Offering — Debentures — Redemption".

After the Final Instalment Date, any Debentures not converted to Common Shares may be redeemed at the option of the Corporation at a price equal to their principal amount plus any unpaid interest which accrued prior to the Final Instalment Date. See "Details of the Offering — Debentures — Redemption".

On January 9, 2024 (the "Maturity Date"), the Corporation will repay the principal amount of any Debentures not converted and remaining outstanding, in cash. The Corporation may, at its option and without prior notice, satisfy the obligation to pay the principal amount of such Debentures on maturity by delivery of that number of freely tradable Common Shares obtained by dividing the principal amount of the Debentures by 95% of the weighted average trading price of the Common Shares on the Toronto Stock Exchange (the "TSX") for the 20 consecutive trading days ending five trading days preceding the Maturity Date.

Price: $1,000 per Debenture to yield 4.00% per annum

(each Debenture is convertible into Common Shares at a Conversion Price of $30.72)

	Price to the Public	Underwriters' Fee (1)	Net Proceeds to Selling Debentureholder (2)
Per Debenture			
First Instalment	$333.00	$20.00	$313.00
Final Instalment	$667.00	$20.00	$647.00
Total Per Debenture	$1,000.00	$40.00	$960.00
Total (3)	$1,594,000,000	$63,760,000	$1,530,240,000

(1) The Underwriters' fee is equal to 4.00% of the gross proceeds of the Offering, one-half of which is payable on the Closing Date and the remaining one-half of which is payable on the Final Instalment Date.

(2) Net proceeds to the Selling Debentureholder are calculated before deducting the expenses of the Offering, estimated at $2,000,000, which, together with the Underwriters' fee, will be paid out of the general funds of Fortis. See "Plan of Distribution".

(3) The Selling Debentureholder has granted to the Underwriters an option (the "Over-Allotment Option") to purchase additional Debentures represented by Instalment Receipts equal to up to 15% of the aggregate principal amount of Debentures represented by Instalment Receipts sold on the Closing Date, at a price of $1,000 per Debenture payable on an instalment basis and on the same terms and conditions of the Offering to cover over-allotments, if any. The Over-Allotment Option is exercisable in whole or in part at the Underwriters' sole discretion and without obligation, on or prior to the 30th day following the closing of the Offering. If the Over-Allotment Option is exercised in full, the total "Price to the Public", "Underwriters' Fee" and "Net Proceeds to Selling Debentureholder" will be $1,833,100,000, $73,324,000 and $1,759,776,000, respectively. This short form prospectus qualifies the grant of the Over-Allotment Option and the sale of Debentures represented by Instalment Receipts pursuant to this short form prospectus on the exercise of such option. A purchaser who acquires Debentures represented by Instalment Receipts forming part of the Underwriters' over-allocation position acquires those securities under this short form prospectus, regardless of whether the position is ultimately filled through the exercise of the Over-Allotment Option or secondary market purchases. Unless otherwise indicated, the disclosure in this short form prospectus assumes that the Over-Allotment Option has not been exercised. See "Plan of Distribution".

Underwriters' Position	Maximum size or number of securities held	Exercise Period	Exercise Price
Over-Allotment Option	Option to sell up to $239,100,000 aggregate principal amount of Debentures (on an instalment basis)	At any time within 30 days following the closing of the Offering	$1,000 per Debenture payable on an instalment basis of which $333 is payable on the closing of the Over-Allotment Option and $667 is payable by or before the Final Instalment Date

There is currently no market through which the Debentures represented by Instalment Receipts may be sold and purchasers may not be able to resell securities purchased under this short form prospectus. This may affect the pricing of the securities in the secondary market, the transparency and availability of trading prices, the liquidity of the securities and the extent of issuer regulation. See "Risk Factors".

This short form prospectus qualifies for distribution the Debentures represented by the Instalment Receipts. The TSX has conditionally approved the listing of the Instalment Receipts (representing the Debentures and the Private Placement Debentures) and the Common Shares issuable on the conversion of the Debentures and Private Placement Debentures on the TSX, subject to Fortis fulfilling all of the requirements of the TSX on or before March 11, 2014. **The Corporation has no current intention to list the Debentures or the Private Placement Debentures for trading on any exchange as it currently anticipates all Debentures and Private Placement Debentures will be converted to Common Shares on the Final Instalment Date.** The Corporation's outstanding Common Shares are listed on the TSX under the symbol "FTS". On December 11, 2013, the last trading day prior to the announcement of the Acquisition, the Offering and the Concurrent Private Placement, the closing price of the Common Shares on the TSX was $31.19. On December 19, 2013, the closing price of the Common Shares on the TSX was $30.11.

The Debentures will be sold by the Selling Debentureholder to the Underwriters (as defined below) on an instalment basis for a total of $1,000 per Debenture, which price and other terms of the Offering were determined by negotiation between the Corporation, the Selling Debentureholder and the Underwriters. After a reasonable effort has been made to sell all of the Debentures at the price specified above, the Underwriters may subsequently reduce the selling price to investors from time to time in order to sell any of the Debentures remaining unsold. Any such reduction will not affect the proceeds received by the Selling Debentureholder. **See "Plan of Distribution".**

An investment in the Debentures represented by Instalment Receipts, and the Common Shares issuable upon the conversion of Debentures, involves certain risks that should be considered by a prospective purchaser. See "Risk Factors" and "Special Note Regarding Forward-Looking Statements".

Each of Scotia Capital Inc. ("Scotia Capital"), RBC Dominion Securities Inc. ("RBC"), TD Securities Inc. ("TDSI"), CIBC World Markets Inc. ("CIBC"), BMO Nesbitt Burns Inc., National Bank Financial Inc. and Desjardins Securities Inc. are acting as underwriters (collectively, the "Underwriters") of the Offering. The Underwriters, as principals, conditionally offer the Debentures represented by Instalment Receipts, subject to prior sale, if, as and when issued, sold and delivered by the Selling Debentureholder to, and accepted by, the Underwriters in accordance with the terms and conditions contained in the Underwriting Agreement referred to under "Plan of Distribution" and subject to the approval of certain legal matters on behalf of the Corporation and the Selling Debentureholder by Davies Ward Phillips & Vineberg LLP, Toronto and McInnes Cooper, St. John's, and on behalf of the Underwriters by Stikeman Elliott LLP, Toronto. Subject to applicable laws, the Underwriters may, in connection with the Offering, effect transactions which stabilize or maintain the market price of the Instalment Receipts representing the Debentures or the Common Shares at levels above those which may prevail on the open market. Such transactions, if commenced, may be discontinued at any time. See "Plan of Distribution".

Each of the Underwriters is an affiliate of a financial institution that has, either solely or as a member of a syndicate of financial institutions, extended (or will extend) credit facilities to, or holds (or will hold) other indebtedness of, the Corporation and/or its subsidiaries. In addition, Scotia Capital, RBC, TDSI and CIBC are acting as agents in the Concurrent Private Placement and will receive an agency fee in connection with such role. See "Financing the Acquisition". **Consequently, the Corporation may be considered a "connected issuer" of these Underwriters within the meaning of applicable securities legislation. See "Relationship between Fortis, the Selling Debentureholder and Certain Underwriters".**

Subscriptions for the Debentures represented by Instalment Receipts will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that the Closing Date will take place on or about January 9, 2014, or such other date as may be agreed upon by the Corporation, the Selling Debentureholder and the Underwriters, but not later than January 20, 2014. The Debentures represented by Instalment Receipts offered hereby are to be taken up by the Underwriters, if at all, on or before a date not later than 42 days after the date of the receipt for the final short form prospectus relating to the Offering.

A book-entry only certificate representing the Instalment Receipts (representing the Debentures) distributed hereunder will be issued in registered form only to CDS Clearing and Depository Services Inc. ("CDS") or its nominee and will be deposited with CDS on the Closing Date. Subject to compliance with the provisions of the Instalment Receipt Agreement, as soon as practicable on or after the Final Instalment Date provided that payment of the final instalment has been made, the global certificate representing the Instalment Receipts will be cancelled and the global certificate representing the Debentures distributed hereunder, pledged to the Selling Debentureholder and held by Computershare Trust Company of Canada, as security agent, will be discharged, released and delivered to CDS and registered in the name of CDS or its nominee (as adjusted for Debentures that have been converted into Common Shares on the Final Instalment Date). The Corporation understands that a purchaser of Debentures represented by Instalment Receipts will receive only a customer confirmation from the registered dealer (who is a CDS participant) from or through whom the Debentures represented by Instalment Receipts are purchased. Except as otherwise stated herein, neither the holders of Instalment Receipts representing Debentures nor the holders of Debentures on or following the Final Instalment Date will be entitled to receive physical certificates representing their ownership thereof, as applicable. See "Details of the Offering".

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Please refer to the "Glossary of Terms" beginning on page 95 of this short form prospectus (the "Prospectus") for a list of defined terms used herein.

This Prospectus, including the documents incorporated herein by reference, contain forward-looking information which reflects management's current expectations regarding: (i) the future growth, results of operations, performance, business prospects and opportunities of the Corporation; (ii) the Acquisition of UNS Energy; (iii) the impact of the Acquisition, this Offering, the Concurrent Private Placement and the Acquisition Credit Facilities on the financial position of the Corporation; and (iv) the future performance, business prospects and opportunities of UNS Energy and the integration of its electric and gas utility businesses with the existing operations of Fortis. These expectations 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", "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 and is based on information currently available to the Corporation's management.

The forward-looking information in this Prospectus, including the documents incorporated herein by reference, includes, but is not limited to, statements regarding: the principal business of Fortis remaining the ownership and operation of regulated electric and gas utilities; the Corporation's primary focus on the United States and Canada in the acquisition of regulated utilities; the pursuit of growth in the Corporation's non-regulated businesses in support of its regulated utility growth strategy; the expected capital investment in Canada's electricity sector over the 20-year period from 2010 through 2030 to maintain system reliability; forecasted rate base for the Corporation's largest regulated utilities; the Corporation's consolidated forecasted gross capital expenditures for 2013 and in total over the six years from 2013 through 2018; the expectation that the CH Energy Acquisition will be accretive to earnings per Common Share in the first full year following its completion, excluding one-time Acquisition-Related Expenses; the expected timing and completion of the Tilbury LNG Facility expansion and the increased liquefaction and storage capacity of such facility following the expansion; the expected combined CAGR of utility rate base and hydroelectric generation investment over the next six years; the expectation that FortisAlberta's load and rate base will be positively impacted as a result of continuing economic growth in Alberta; various natural gas and electricity distribution or transmission investment opportunities that may be available to the Corporation; the nature, timing and amount of certain capital projects and their expected costs and time to complete; the expectation that the Corporation's capital expenditure program will support continuing growth in earnings and dividends; the expectation that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed; the expectation that the Corporation's regulated utilities could experience disruptions and increased costs if they are unable to maintain their asset base; 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 (or otherwise finance) the cash required to fund their capital expenditure programs; the expected consolidated long-term debt maturities and repayments on average annually over the next five years; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to capital in the near to medium 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 2013; the expectation that any increase in interest expense and/or fees associated with renewed and extended credit facilities will not materially impact the Corporation's consolidated financial results for 2013; the expected impact on 2013 earnings for FortisAlberta and FortisBC of changes in the allowed ROE and common equity component of total capital structure; the expected timing of filing of regulatory applications and of receipt of regulatory decisions; the estimated impact a decrease in revenue at Fortis Properties' Hospitality Division would have on annual basic earnings per Common Share; no expected material adverse credit rating actions in the near term; the expected impact of a change in the U.S. dollar-to-Canadian dollar foreign exchange rate on basic earnings per Common Share in 2013; the expectation that counterparties to the FortisBC Energy companies' gas derivative contracts will continue to meet their obligations; the expectation that consolidated defined benefit net pension cost for 2013 will be comparable to that in 2012 and that there is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future.

The forward-looking information contained herein pertaining to the Acquisition and the financing thereof, the future performance, business prospects and opportunities of UNS Energy and the integration of its electric and gas utility businesses with the existing operations of Fortis includes, but is not limited to, statements regarding: the terms and conditions of the Acquisition; the completion of the Acquisition; the realization of the anticipated benefits of the Acquisition by Fortis, including that the Acquisition will be accretive to the Corporation's earnings per Common Share in the first full year following its completion, excluding one-time Acquisition-Related Expenses; the accuracy of the *pro forma* combined financial information, which does not purport to be indicative of the financial information that will result from the operations of Fortis on a consolidated basis following the Acquisition; the completion of the Offering and the Concurrent Private Placement and the use of the proceeds therefrom; the conversion of the Debentures and the Private Placement Debentures into Common Shares and the impact of such conversion on the consolidated capitalization of Fortis; the receipt by the Selling Debentureholder of the aggregate amount of the final instalment payable in respect of the Debentures; the utilization by Fortis of the Acquisition Credit Facilities; the entering into by Fortis and the Selling Debentureholder of the Instalment Receipt Agreement and the Indenture; the rights of holders of Instalment Receipts to receive Debentures and Common Shares on the occurrence of certain events; the listing of the Instalment Receipts and Common Shares issuable on the exercise of the Debentures on the TSX; the rate of return and payment of interest on the Debentures; the impact of the Acquisition on a consolidated basis on the Corporation's operations, infrastructure, opportunities, financial condition, access to capital and overall strategy; the ability of Fortis to satisfy its liabilities and meet its debt service obligations following completion of the Acquisition; the potential for the credit rating of Fortis to change as a result of the Acquisition and the financing thereof; the expectation that Fortis will retain key employees of UNS Energy and its subsidiaries; the performance, business prospects and opportunities of UNS Energy and its subsidiaries; the regulatory environment in the State of Arizona; the projected growth in jobs, retail sales and personal income in the State of Arizona for the six years from 2013 through 2018 and the projected growth in jobs for the 30 years ending in 2043; the expectation that there will be a material decrease in the use of coal by TEP in its generating stations and the expected ratio of generating fuels to be used by TEP in 2020; the anticipated impact of current and future environmental regulations on the business and operations of the UNS Utilities; the impact on the UNS Utilities of regulatory requirements relating to energy efficiency and renewable energy; the continued operation by TEP of its current generating stations; the expectation that labour relations with unionized employees of UNS Energy and its subsidiaries will continue to be good; the nature, timing and amount of certain capital projects; and expectations in respect of the operations, inventory, supply and generating capacity of the assets of UNS Energy and its subsidiaries.

The forecasts and projections that make up the forward-looking information included in this Prospectus are based on assumptions which include, but are not limited to: the completion of the Acquisition; the receipt of applicable regulatory approvals and requested rate orders; the receipt of UNS Energy shareholder approval and regulatory approvals relating to the Acquisition on terms acceptable to Fortis; the payment to the Selling Debentureholder of the aggregate amount of the final instalment; the conversion of all of the Debentures distributed pursuant to this Prospectus and in the Concurrent Private Placement into Common Shares; the realization of the anticipated benefits of the Acquisition; the ability of Fortis to successfully integrate the business and operations of UNS Energy into the Fortis group of companies; the ability of Fortis to retain key employees of UNS Energy and the UNS Utilities; the rate of growth in jobs, retail sales and personal income in the State of Arizona for the six years from 2013 through 2018 and the rate of growth in jobs for the 30 years ending in 2043; the amount of borrowings to be drawn down under the Acquisition Credit Facilities; the ability of Fortis to access the capital markets following the Acquisition to effect the repayment of the Acquisition Credit Facilities in accordance with their terms; the aggregate amount of the Acquisition-Related Expenses; the accuracy and completeness of the UNS Energy public and other disclosure incorporated in this Prospectus; the absence of undisclosed liabilities of UNS Energy; no material adverse regulatory decisions being received and the expectation of regulatory stability; FortisAlberta continuing to recover its cost of service and earn its allowed ROE under the PBR setting, which commenced for a five-year term effective January 1, 2013; 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 gas and electricity systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; no material capital project and financing cost overrun or delay related to the construction of the Waneta Expansion; sufficient liquidity and capital resources; the expectation that the Corporation will receive appropriate compensation from the GOB for fair value of the Corporation's investment in Belize Electricity that was expropriated by the GOB; the expectation that BECOL will not be expropriated by the GOB; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates at Fortis and UNS Energy and their respective subsidiaries and environmental costs at UNS Energy and its subsidiaries in customer rates; the ability to hedge exposures to fluctuations in interest rates, foreign exchange rates, natural gas commodity prices, electricity prices, coal prices and other fuel prices; the price obtainable from time to time for wholesale electricity and gas sales in the southwestern United States; continued favourable relations with co-owners or operators at generating plants in which TEP has an interest; the cost at which replacement sources of power could be obtained by TEP; the rate of decline in power consumption resulting from energy efficiency programs and customer-oriented generation; the continuation of observed weather patterns and trends; 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 generate electricity using coal in the State of Arizona and the State of New Mexico; 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; the absence of 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; the ability of TEP to continue to receive electricity on a cost-effective basis from the generating stations in which it currently has an interest; the amount of capital expenditures which will be required to bring the generation assets of TEP and UNS Electric into compliance with current and future environmental regulations; no material change in public policies and directions by governments that could materially negatively affect the Corporation, UNS Energy and their respective subsidiaries; 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 2014 or the adoption of IFRS after 2014 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; 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. Factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory risk, including risks relating to pending and future changes in environmental regulations and increased risk at FortisAlberta associated with the adoption of PBR for a five-year term commencing in 2013; interest rate risk, including the uncertainty of the impact a continuation of a low interest rate environment may have on the ROE of the Corporation's regulated utilities; operating and maintenance risks; risks associated with changes in economic conditions; capital project budget overrun, completion and financing risk in the Corporation's non-regulated business; capital resources and liquidity risk; risk associated with the amount of compensation to be paid to Fortis for its investment in Belize Electricity that was expropriated by the GOB; the timeliness of the receipt of the compensation and the ability of the GOB to pay the compensation owing to Fortis; risk that the GOB may expropriate BECOL; weather and seasonality risk; commodity price risk; the continued ability to hedge foreign exchange risk; counterparty risk; competitiveness of natural gas; natural gas, fuel, coal and electricity supply risk; risk associated with the continuation, renewal, replacement and/or regulatory approval of power supply and capacity purchase contracts; risks relating to the inability to complete the Acquisition; risks relating to the realization of the anticipated benefits of the Acquisition; risks associated with a material decrease in the price of the Common Shares, and the impact this would have on the amount of Debentures ultimately required to be purchased or repaid at maturity by the Corporation; risks associated with the economic viability of bringing certain of the generating assets of TEP into compliance with current and future environmental regulations; risks associated with the co-ownership or lease of certain generating assets of TEP; risks associated with the cost of purchasing TEP's leased assets and the cost of procuring alternate sources of generation or purchased power; risks associated with TEP not being the operator of certain of the generating stations in which it has an interest; risks associated with defined benefit pension plan performance and funding requirements; risks related to FEVI; environmental risks; insurance coverage risk; risk of loss of licences and permits; risk of loss of service area; risk of not being able to report under US GAAP beyond 2014 or risk that IFRS does not have an accounting standard for rate-regulated entities by the end of 2014 allowing for the recognition of regulatory assets and liabilities; risks related to changes in tax legislation; risk of failure of information technology infrastructure and cyber-attack; risk of not being able to access First Nations lands; labour relations risk; human resources risk; and risk of unexpected outcomes of legal proceedings currently against the Corporation or UNS Energy. For additional information with respect to the Corporation's risk factors and risk factors relating to the post-Acquisition business of Fortis, the operations of Fortis and UNS Energy, the Acquisition, the Debentures, the Instalment Receipts and Common Shares, reference should be made to the section of this Prospectus entitled "Risk Factors" and to the documents incorporated herein by reference and to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities.

All forward-looking information in this Prospectus and in the documents incorporated herein by reference 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.

DOCUMENTS INCORPORATED BY REFERENCE

The disclosure documents of the Corporation listed below and filed with the appropriate securities commissions or similar regulatory authorities in each of the provinces of Canada are specifically incorporated by reference into and form an integral part of this Prospectus:

(i) the AIF;

(ii) audited comparative consolidated financial statements as at December 31, 2012 and December 31, 2011 and for the years ended December 31, 2012 and 2011, together with the notes thereto and the auditors' report thereon dated March 20, 2013, as contained in the Corporation's 2012 Annual Report, prepared in accordance with US GAAP;

(iii) the Annual MD&A;

(iv) the Management Information Circular;

(v) unaudited comparative interim consolidated financial statements as at September 30, 2013 and for the three and nine months ended September 30, 2013 and 2012, together with the notes thereon, prepared in accordance with US GAAP;

(vi) Management Discussion and Analysis of financial condition and results of operations for the three and nine months ended September 30, 2013;

(vii) the template version of the term sheet dated December 11, 2013 and the template version of the investor presentation dated December 11, 2013, each filed on SEDAR in connection with the Offering (collectively, the "Marketing Materials"); and

(viii) the material change report dated December 12, 2013 announcing the Acquisition and the financing thereof, including this Offering and the Concurrent Private Placement.

Any document of the type referred to in the preceding paragraph, any material change report (other than any confidential material change report) and any business acquisition report subsequently filed by the Corporation with such securities commissions or regulatory authorities after the date of this Prospectus, and prior to the termination of the Offering, shall be deemed to be incorporated by reference into this Prospectus.

Any statement contained in a document incorporated or deemed to be incorporated by reference in this Prospectus shall be deemed to be modified or superseded for purposes of this Prospectus to the extent that a statement contained herein, or in any other subsequently filed document which also is incorporated or is deemed to be incorporated by reference herein, modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement will not be deemed an admission for any purpose that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this Prospectus.

Copies of the documents incorporated herein by reference may be obtained on request without charge from the Secretary of the Corporation at Suite 1201, 139 Water Street, St. John's, Newfoundland and Labrador A1B 3T2 (telephone (709) 737-2800). These documents are also available through the Internet on the Corporation's website at www.fortisinc.com or on SEDAR which can be accessed at www.sedar.com. The information contained on, or accessible through, any of these websites is not incorporated by reference into this Prospectus and is not, and should not be considered to be, a part of this Prospectus, unless it is explicitly so incorporated.

MARKETING MATERIALS

The Marketing Materials are not part of this Prospectus to the extent that the contents of the Marketing Materials have been modified or superseded by a statement contained in this Prospectus. Any template version of "marketing materials" (as defined in National Instrument 41-101 — *General Prospectus Requirements*) filed after the date of this Prospectus and before the termination of the distribution under the Offering (including any amendments to, or an amended version of, the Marketing Materials) are deemed to be incorporated into this Prospectus.

ELIGIBILITY FOR INVESTMENT

In the opinion of Davies Ward Phillips & Vineberg LLP, counsel to Fortis and the Selling Debentureholder, and Stikeman Elliott LLP, counsel to the Underwriters, provided that the Common Shares are listed on a "designated stock exchange" (which includes the TSX) for the purposes of the Tax Act and subject to the provisions of any particular Exempt Plan (as defined below), the Debentures represented by Instalment Receipts and the Common Shares issuable on the conversion or maturity of the Debentures, if issued on the date hereof, would be qualified investments under the Tax Act as of the date hereof for a trust governed by a RRSP, a RRIF, a registered education savings plan, a DPSP, a registered disability savings plan and a TFSA (collectively, "Exempt Plans"), except, in the case of the Debentures, a DPSP to which Fortis, or an employer that does not deal at arm's length with Fortis, has made a contribution.

Notwithstanding the foregoing, if the Debentures or the Common Shares are a "prohibited investment" (as defined in the Tax Act) for a trust governed by a TFSA, RRSP or RRIF, the holder or annuitant thereof, as the case may be, will be subject to a penalty tax as set out in the Tax Act. The Debentures and Common Shares will not be a prohibited investment for a TFSA, RRSP or RRIF provided the holder or annuitant of such Exempt Plan, as the case may be, (i) deals at arm's length with Fortis, for purposes of the Tax Act and (ii) does not have a "significant interest" (as defined in the prohibited investment rules in the Tax Act) in Fortis. In addition, Common Shares will not be a "prohibited investment" if the Common Shares are "excluded property" as defined in the Tax Act for this purpose for trusts governed by a TFSA, RRSP and RRIF. Prospective purchasers who intend to hold Debentures or Common Shares in a TFSA, RRSP or RRIF are advised to consult their personal tax advisors.

PRESENTATION OF FINANCIAL INFORMATION

The financial statements of the Corporation included in this Prospectus are reported in Canadian dollars and have been prepared in accordance with US GAAP. All other financial information of UNS Energy and the audited historical financial statements of UNS Energy included in this Prospectus are reported in U.S. dollars and have been prepared in accordance with US GAAP. The assets and liabilities of UNS Energy shown in the unaudited *pro forma* consolidated balance sheet of the Corporation as at September 30, 2013 are reported in Canadian dollars and reflect the U.S.-to-Canadian dollar period-end closing exchange rate. The revenues and expenses of UNS Energy shown in the unaudited *pro forma* consolidated statements of earnings of the Corporation for the nine month period ended September 30, 2013 and for the year ended December 31, 2012 are reported in Canadian dollars and reflect the average U.S.-to-Canadian dollar exchange rates for such periods. Financial information in this Prospectus that has been derived from the unaudited *pro forma* consolidated financial statements has been translated to Canadian dollars on the same basis. Certain tables in the Prospectus may not add due to rounding.

CAUTION REGARDING UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

This Prospectus contains the unaudited *pro forma* consolidated balance sheet as at September 30, 2013 and consolidated statements of earnings of the Corporation as at and for the nine month period ended September 30, 2013 and for the year ended December 31, 2012, giving effect to: (i) the Offering, assuming no exercise of the Over-Allotment Option; (ii) the Concurrent Private Placement; (iii) the issuance of Common Shares upon the conversion of the Debentures and the Private Placement Debentures on the Final Instalment Date; (iv) the Acquisition Credit Facilities; and (v) the Acquisition. Such unaudited *pro forma* consolidated financial statements have been prepared using certain of the Corporation's and UNS Energy's respective financial statements as more particularly described in the notes to such unaudited *pro forma* consolidated financial statements. In preparing such unaudited *pro forma* consolidated financial statements, Fortis has had limited access to the non-public books and records of UNS Energy and makes no representation or warranty as to the accuracy or completeness of such information provided by

UNS Energy, including the financial statements of UNS Energy that were used to prepare the unaudited *pro forma* consolidated financial statements. Such unaudited *pro forma* consolidated financial statements are not intended to be indicative of the results that would actually have occurred, or the results expected in future periods, had the events reflected herein occurred on the dates indicated. Actual amounts recorded upon the finalization of the purchase price allocation under the Acquisition may differ from such unaudited *pro forma* consolidated financial statements. Since the unaudited *pro forma* consolidated financial statements have been developed to retroactively show the effect of a transaction that has or is expected to occur at a later date (even though this was accomplished by following generally accepted practice using reasonable assumptions), there are limitations inherent in the very nature of *pro forma* data. The data contained in the unaudited *pro forma* consolidated financial statements represents only a simulation of the potential impact of the Corporation's acquisition of UNS Energy. Undue reliance should not be placed on such unaudited *pro forma* consolidated financial statements. See "Special Note Regarding Forward-Looking Statements" and "Risk Factors".

CURRENCY

In this Prospectus, unless otherwise specified or the context otherwise requires, all dollar amounts are expressed in Canadian dollars. References to "dollars", "$" or "Cdn$" are to lawful currency of Canada. References to "U.S. dollars" or "US$" are to lawful currency of the United States of America.

The following table sets forth, for each of the periods indicated, the period-end closing exchange rate, the average noon exchange rate and the high and low noon exchange rates of one U.S. dollar in exchange for Canadian dollars as reported by the Bank of Canada.

	Year ended December 31,			Nine months ended September 30,	
	2012	**2011**	**2010**	**2013**	**2012**
High	1.0418	1.0604	1.0778	1.0576	1.0418
Low	0.9710	0.9449	0.9946	0.9839	0.9710
Average	0.9996	0.9891	1.0299	1.0235	1.0022
Period End	0.9949	1.0170	0.9946	1.0303	0.9832

On December 19, 2013, the closing exchange rate as reported by the Bank of Canada was US$1.00 = Cdn$1.0666

DEFINED TERMS

For an explanation of certain terms and abbreviations used in, and conversions applicable to, this Prospectus, reference is made to the "Glossary of Terms" beginning on page 95 of this Prospectus.

THIRD PARTY SOURCES AND INDUSTRY DATA

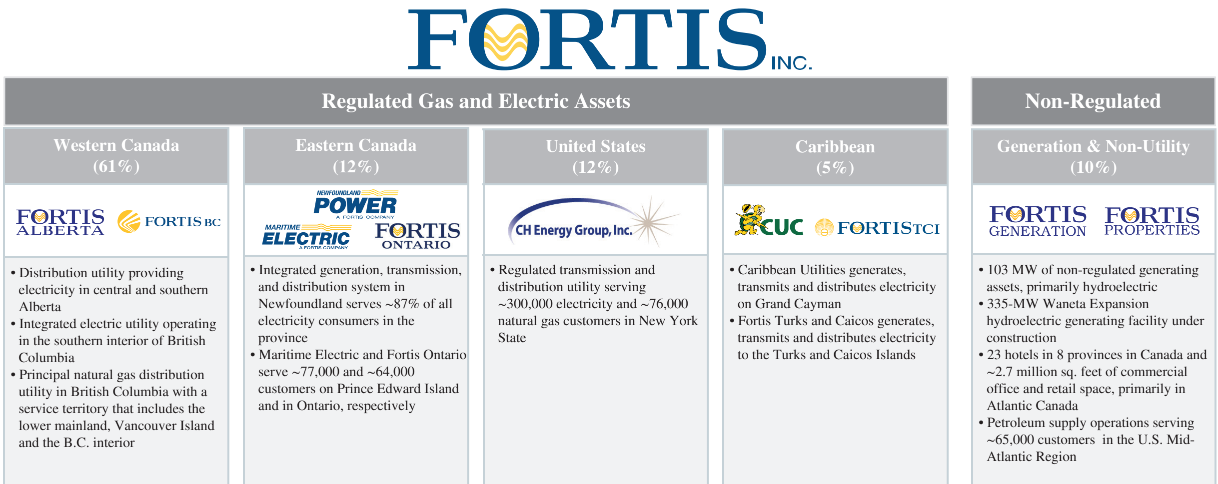
This Prospectus contains information from publicly available third party sources as well as industry data prepared by management on the basis of its knowledge of the regulated utility industry in which Fortis operates (including management's estimates and assumptions relating to the industry based on that knowledge). Management's knowledge of the regulated utility industry has been developed through its experience and participation in the industry. Management believes that its industry data is accurate and that its estimates and assumptions are reasonable, but there can be no assurance as to the accuracy or completeness of this data. Third-party sources, which include the University of Arizona Economic and Business Research Center and DBRS, generally state that the information contained therein has been obtained from sources believed to be reliable, but there can be no assurance as to the accuracy or completeness of included information. Although management believes it to be reliable, none of Fortis, the Selling Debentureholder or the Underwriters have independently verified any of the data from third-party sources referred to in this Prospectus or analyzed or verified the underlying studies or surveys relied upon or referred to by such sources, or ascertained the underlying economic assumptions relied upon or referred to by such sources.

PROSPECTUS SUMMARY

The following information is a summary only and is to be read in conjunction with, and is qualified in its entirety by, the more detailed information and financial data and statements appearing elsewhere in this Prospectus and in the documents incorporated by reference herein. Please refer to the "Glossary of Terms" beginning on page 95 of this Prospectus for a list of defined terms used herein.

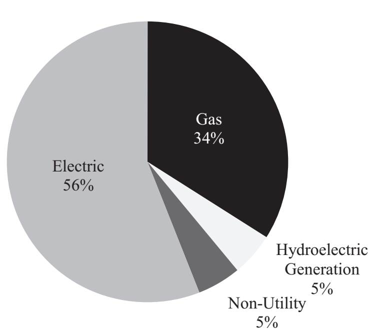
FORTIS

Fortis is the largest investor-owned gas and electric distribution utility in Canada with total assets of approximately $17.6 billion as at September 30, 2013 and fiscal 2012 revenue (which excludes the June 2013 acquisition of CH Energy Group) totalling approximately $3.7 billion. The Corporation serves more than 2,400,000 customers across Canada and in New York State and the Caribbean. Its regulated holdings include electric distribution utilities in five Canadian provinces, New York State and two Caribbean countries and natural gas utilities in British Columbia, Canada and New York State. See "Fortis".

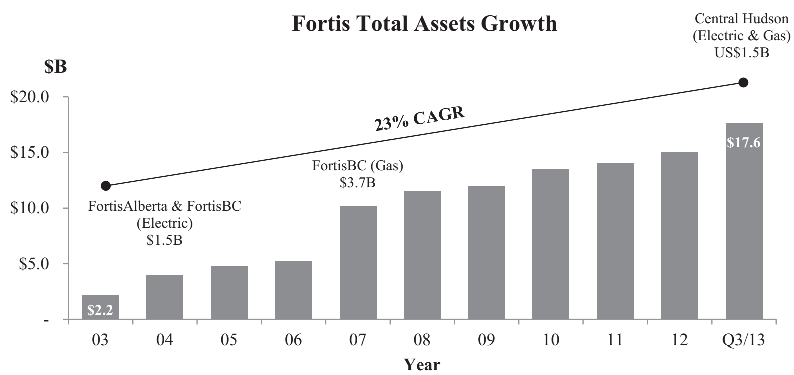


As at September 30, 2013, regulated utility assets comprised approximately 90% of the Corporation's total assets, with the balance comprised of non-regulated generation assets, commercial office and retail space, hotels and petroleum supply operations. Over the last decade, total assets of Fortis have grown at a CAGR of 23%.

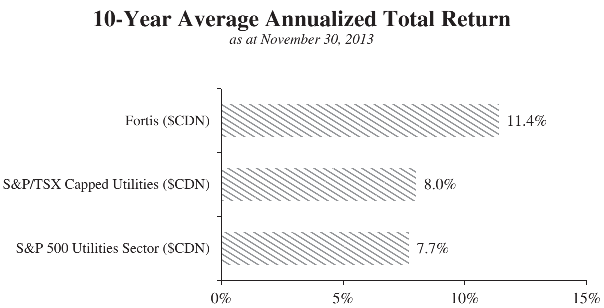
90% Regulated Assets

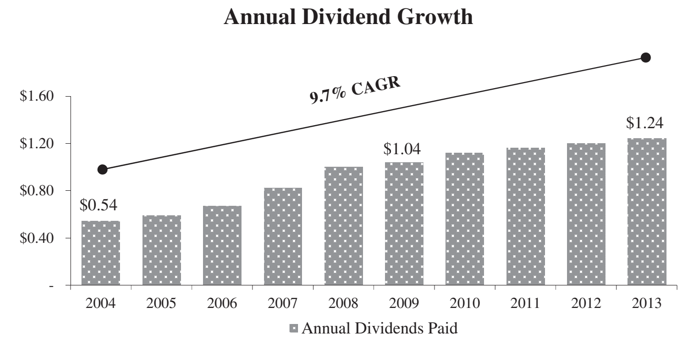


Fortis Total Assets Growth

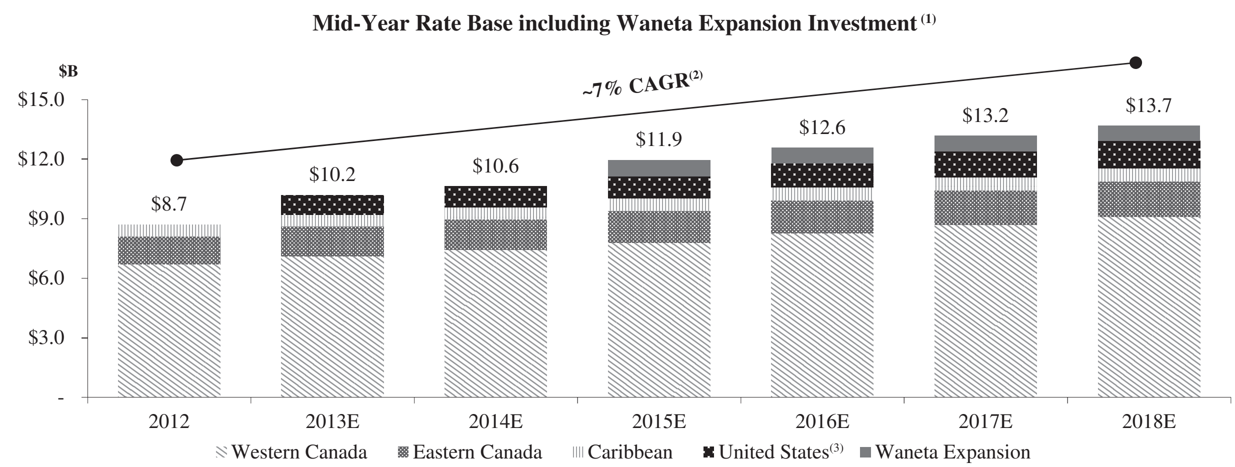


Earnings and dividend growth at Fortis have resulted in annualized total shareholder returns of 11.4% over the past 10 years. Over the same period, Fortis has maintained average annual dividend growth of 9.7%.





Over the six years from 2013 through 2018, the Corporation's consolidated capital expenditure program, which is mostly funded at the individual subsidiary level and includes expenditures at Central Hudson, the Waneta Expansion and the Tilbury LNG Facility expansion, is expected to approximate $7.5 billion. Capital investment should allow the Corporation's consolidated regulated mid-year rate base, including incremental investment in rate base by Central Hudson and investment in the non-regulated Waneta Expansion, to increase at a combined CAGR of approximately 7% through 2018. Investment in energy infrastructure (rate base) to provide safe, reliable and cost-effective energy service to customers is expected to be the primary driver of earnings growth.



(1) Rate base includes 100% of the Waneta Expansion Project investment (51% ownership) to be completed by Spring 2015 and Caribbean Utilities (~60% ownership).

(2) CAGR excludes the initial ~$1B rate base addition in 2013 related to the Central Hudson acquisition.

(3) Assumes C$/US$ FX rate of 1.03.

THE ACQUISITION

On December 11, 2013, Fortis and certain subsidiaries of Fortis entered into the Acquisition Agreement with UNS Energy which provides for, among other things, the Acquisition by an indirect wholly owned subsidiary of Fortis of all of the issued and outstanding common shares of UNS Energy and the merger of the acquiring subsidiary of Fortis into UNS Energy. The aggregate purchase price for the Acquisition is approximately US$4.3 billion, comprised of approximately US$2.5 billion in cash on closing and the assumption of approximately US$1.8 billion of debt. The Acquisition is subject to receipt of UNS Energy common shareholder approval and certain regulatory and governmental approvals, including approval by each of the ACC and FERC and the satisfaction of customary closing conditions. The closing of the Acquisition is currently expected to occur by the end of 2014.

UNS Energy, formerly UniSource Energy Corporation, is a utility services holding company headquartered in Tucson, Arizona engaged through its subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona. UNS Energy's fiscal 2012 operating revenue totalled approximately US$1.5 billion and, as at September 30, 2013, UNS Energy had total assets of approximately US$4.3 billion. Based on *pro forma* financial information as at September 30, 2013, following the Acquisition, the Corporation's total assets will increase by approximately 33.5% to approximately $23.5 billion. The Acquisition of UNS Energy is expected to increase the Corporation's consolidated rate base by approximately US$3.0 billion by 2015 and its total customers by approximately 654,000. Following the Acquisition, the regulated utility subsidiaries of Fortis will serve more than 3,000,000 customers. See "The Acquisition".

UNS Energy Overview

UNS Energy has three direct and indirect subsidiaries which are regulated utilities: TEP, UNS Gas and UNS Electric. UNS Energy's utility operations are vertically integrated with generation, transmission and distribution being regulated by either the ACC or FERC.

TEP is a vertically integrated regulated electric utility and is UNS Energy's largest and principal operating subsidiary, representing approximately 84% of the total assets as at September 30, 2013 and approximately 81% of the operating revenues of UNS Energy for the nine months ended September 30, 2013. TEP was incorporated in the State of Arizona in 1963 and currently generates, transmits and distributes electricity to approximately 412,000 retail electric customers in southern Arizona. TEP's service territory covers 1,155 square miles (2,991 square kilometres) and includes a population of approximately 1,000,000 people in the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells electricity to other entities in the western United States.

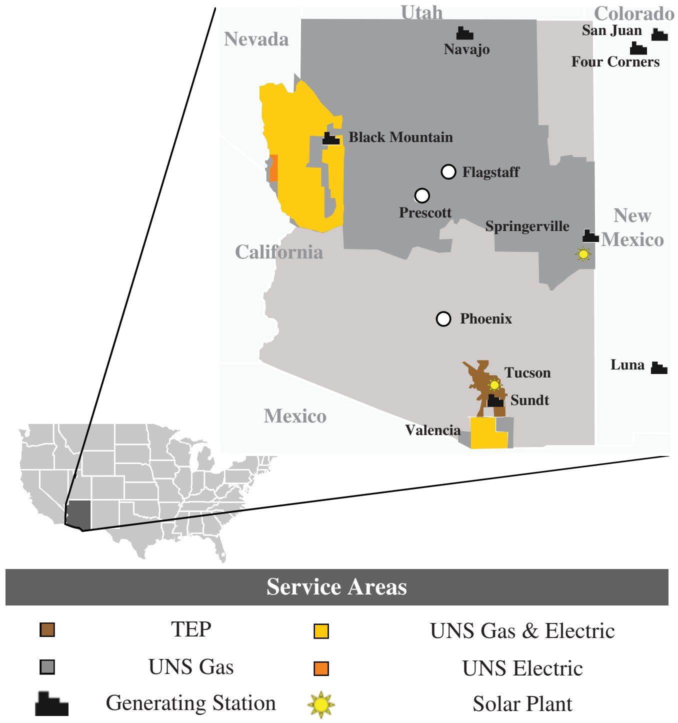
UNS Gas is a regulated gas distribution company serving approximately 149,000 retail customers in northern Arizona's Mohave, Yavapai, Coconino and Navajo counties, as well as Santa Cruz County in southern Arizona. These counties, with a combined population of approximately 700,000, comprise approximately 50% of the territory in the State of Arizona. UNS Gas represented approximately 7% of the total assets of UNS Energy as at September 30, 2013 and approximately 8% of the operating revenues of UNS Energy for the nine months ended September 30, 2013.

UNS Electric is a vertically integrated regulated electric utility company serving approximately 93,000 retail customers in Arizona's Mohave and Santa Cruz counties. These counties have a combined population of approximately 250,000. UNS Electric represented approximately 9% of the total assets of UNS Energy as at September 30, 2013 and approximately 11% of the operating revenues of UNS Energy for the nine months ended September 30, 2013.

The non-regulated business of UNS Energy, which comprises less than 1% of UNS Energy's total assets, includes the operations of Millennium and UniSource Energy Development Company. SES, a wholly owned subsidiary of Millennium, provides electrical contracting and meter reading services in Arizona, as well as other services at Springerville.

The following map depicts the service territories and generating stations of UNS Energy and its regulated utility subsidiaries. See “The Acquired Business”.

UNS Energy Utility Service Areas



ACQUISITION HIGHLIGHTS

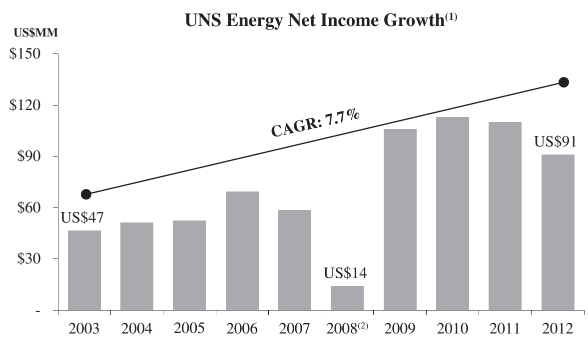
The business operated by UNS Energy is attractive to Fortis for the following reasons:

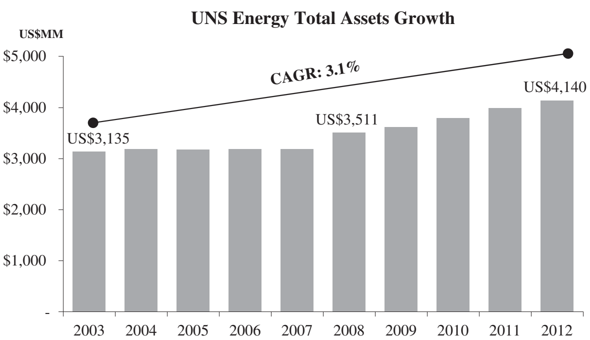
Accretive to Earnings per Common Share in the First Full Year

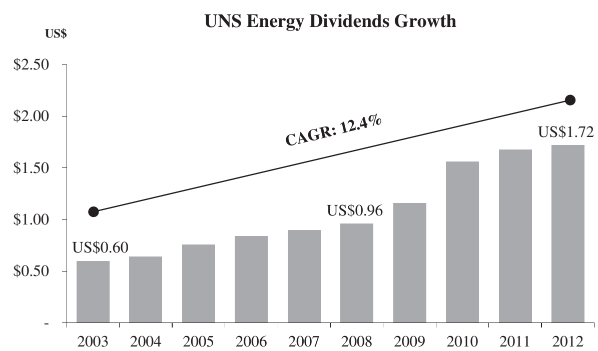
Management expects that the Acquisition will be accretive to the Corporation's earnings per Common Share in the first full year following its completion, excluding one-time Acquisition-Related Expenses. See "The Acquisition Agreement" and "The Acquired Business".

Acquisition of a Well-Run Utility

Over the past 10 years (through 2012), UNS Energy has (i) increased net income by a CAGR of 7.7%, (ii) increased total assets by a CAGR of 3.1% and (iii) increased annual dividends per common share from US$0.60 to US$1.72. Key drivers of earnings growth include the 2013 TEP Rate Order, which is primarily related to prior infrastructure investment, and the expiration and buyout of the Springerville Unit 1 Leases.





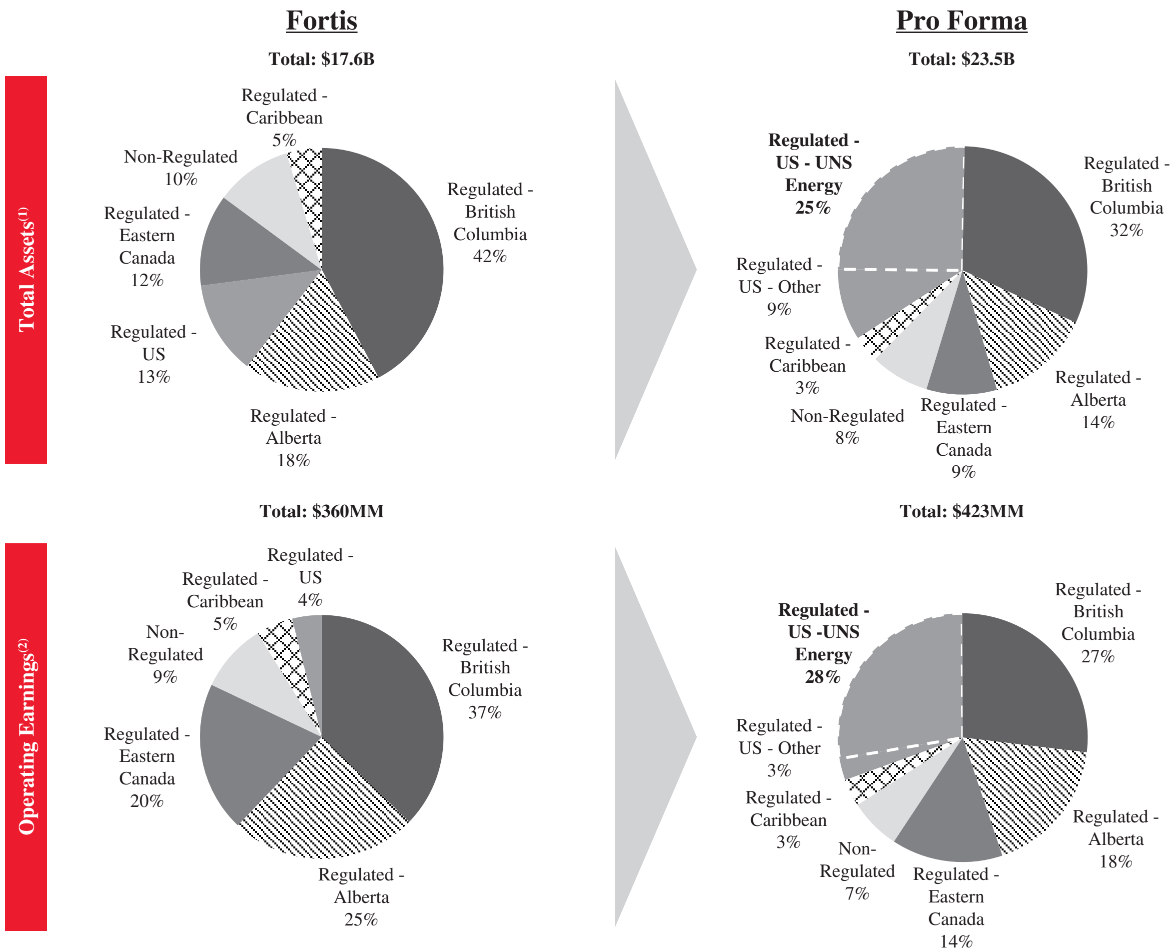


(1) Net income excludes the effect of extraordinary accounting changes and earnings from discontinued operations.

(2) UNS Energy's 2008 net income was reduced due to a US$58 million deduction of revenue for an over-collection of competitive transition charges, which the ACC ordered to be returned to customers, as well as higher fuel and purchased power costs, which prior to January 1, 2009 had not been collected from customers through a flow-through mechanism.

Diversification of Regulated Earnings Base

UNS Energy represents a significant opportunity for Fortis to further diversify its regulated assets, earnings base and cash flows and improve the risk profile of Fortis by diversifying its geographic reach and providing Fortis with a more economically diverse portfolio of assets. The increased diversification to, and growth in, the Corporation's regulated assets, earnings and cash flows is consistent with the Corporation's strategy of pursuing accretive acquisition opportunities both in the United States and Canada.



(1) As at September 30, 2013.

(2) For the nine-month period ended September 30, 2013. Operating earnings of Fortis excludes the $22 million extraordinary gain on settlement of expropriation matters associated with the Exploits River Hydro Partnership.

Supportive Regulatory Environment

UNS Energy operates within a supportive regulatory environment. The regulated utility rates for retail electric and natural gas service are determined by the ACC on a "cost of service" basis with rate design structures that pass through costs related to fuel, purchased power, environmental compliance, energy efficiency and distributed generation. Most of the ACC's regulatory components were recently ranked as "Excellent" or "Very Good" by DBRS.[1] The 2013 TEP Rate Order allows for 10.0% ROE on 43.5% common equity.

[1] Source: DBRS — The Regulatory Framework for Utilities, October 2013.

Favourable Arizona Economic Drivers

Arizona is a state in the southwestern region of the United States with a population of approximately 6.5 million, making it the 15th most populous of the 50 states of the United States. The largest employer in the State is the public service, with copper mining being the State's largest single industry. Copper mined in the state of Arizona accounts for two-thirds of the copper output of the United States.

Additionally, the Arizona economy continues to generate solid economic growth, with job growth at 2.0% over the past year, above the national rate of 1.6%. According to the University of Arizona Economic and Business Research Centre, growth in jobs, retail sales and personal income is expected to reach 2.9%, 5.1% and 6.0%, respectively, by 2018, providing a base of support for future utility earnings. Job growth in Arizona is expected to continue at an annual rate of 1.8% over the next 30 years, reaching 4.3 million jobs by 2043.

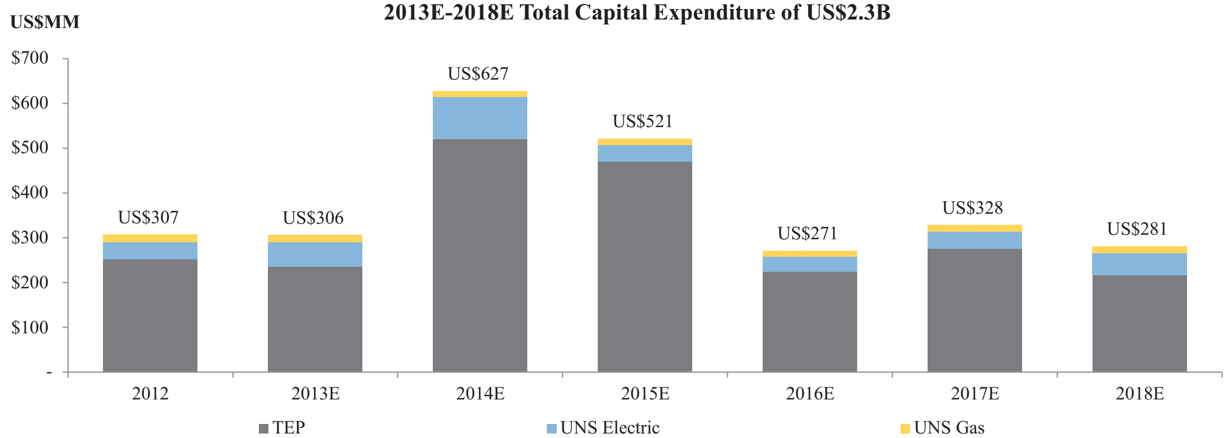
Arizona Economic Forecast (1)

(1) Source: University of Arizona Economic and Business Research Centre, October 2013.

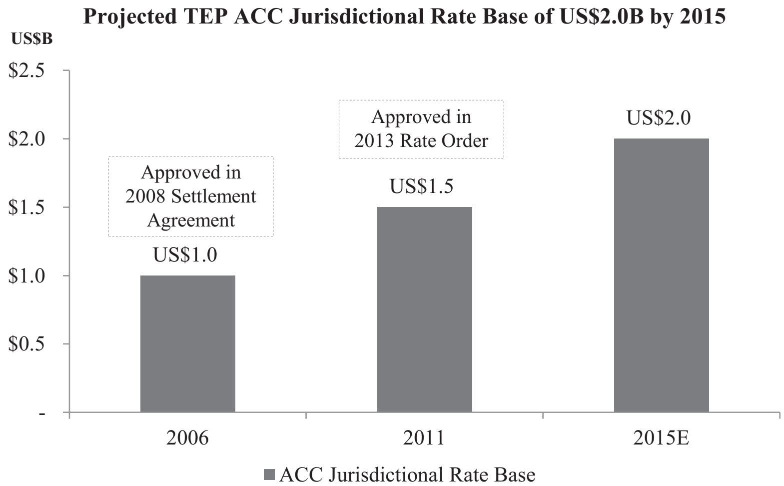
Rate Base Growth

UNS Energy's continued investment in its electric and gas businesses to provide safe, reliable and cost-efficient energy service to its customers is expected to result in attractive rate base growth. UNS Energy has forecasted that capital investment will total approximately US$2.3 billion over the period from 2013 to 2018. UNS Energy's rate base is expected to reach US$3.0 billion by 2015 and to grow at a CAGR of approximately 7% through 2018.

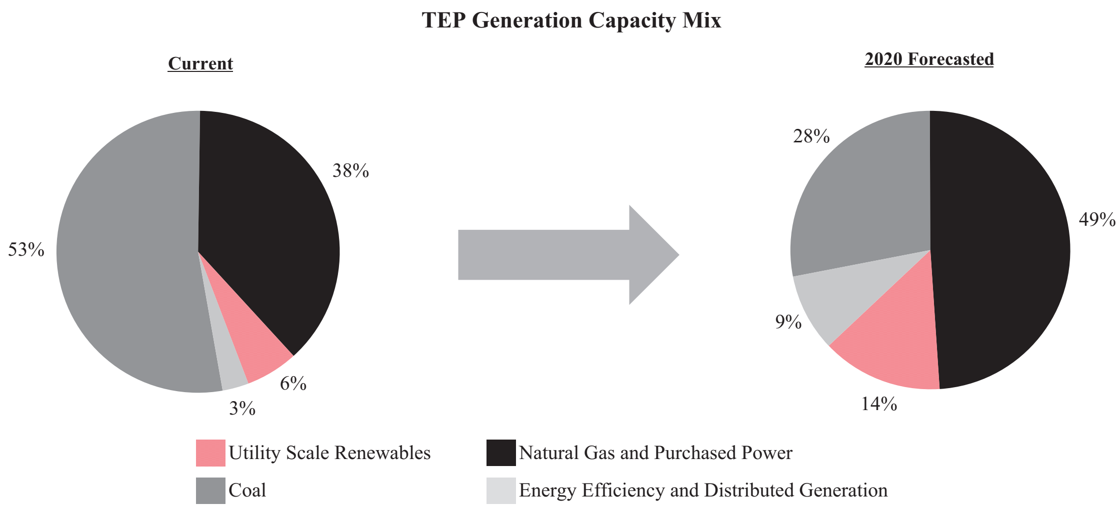
2013E-2018E Total Capital Expenditure of US$2.3B



TEP projects that its ACC jurisdictional rate base will increase to approximately US$2.0 billion by 2015 (from an ACC approved 2011 rate base of US$1.5 billion). This is expected to increase UNS Energy's total rate base to approximately US$3.0 billion by 2015.



TEP expects to invest significant capital into diversifying its generation fleet, including through the anticipated purchase of the natural gas-fired combined-cycle Gila River Unit 3 generation plant (with a capacity of 550 MW) and utility scale renewables generation. Renewables investments will diversify TEP's generation resources, as well as assist TEP in the mitigation of environmental impact.



Experienced Management Team

UNS Energy is a well-run utility with an experienced management team committed to providing customers with safe, reliable and cost-effective energy service. Over the last five years, UNS Energy customers have experienced, on average, approximately one outage for a duration of 1.5 hours per year. Management has decreased debt-to-capitalization of UNS Energy from 84% in 2000 to 62% as at September 30, 2013, resulting in a four notch upgrade to TEP's credit rating over the period to Baa2 (Moody's). Management has also demonstrated strong regulatory expertise, completing each of the past three rate cases in approximately one year on average.

FINANCING THE ACQUISITION

Acquisition Credit Facilities

For purposes of financing the Acquisition, on December 11, 2013, Fortis obtained a commitment letter from The Bank of Nova Scotia providing for an aggregate of $2.0 billion non-revolving term credit facilities in favour of Fortis consisting of a $1.7 billion short-term bridge facility (the "Short-Term Bridge Facility"), repayable in full nine months following its advance, and a $300 million medium-term bridge facility (the "Medium-Term Bridge Facility", and together with the Short-Term Bridge Facility, the "Acquisition Credit Facilities"), repayable in full on the second anniversary of its advance. The Acquisition Credit Facilities, together with the $600 million the Corporation has agreed to maintain under its existing Revolving Facility to cover one-third of the principal amount of the Debentures in the event of a mandatory redemption (as described under "Details of the Offering — Debentures — Redemption"), would be sufficient, if necessary, to fund the full cash portion of the purchase price for the Acquisition.

Fortis is required to make prepayments of the Acquisition Credit Facilities in an amount equal to the net cash proceeds from any common or preferred equity or bond or other debt offerings by Fortis. Net proceeds from any equity offering will be applied firstly to repay the Short-Term Bridge Facility and secondly to repay the Medium-Term Bridge Facility. Net proceeds from any bond or other debt offerings, including the aggregate amount of the final instalment payable under this Offering and the Concurrent Private Placement, will be applied firstly to repay the Medium-Term Bridge Facility and secondly to repay the Short-Term Bridge Facility. Fortis expects that the remainder of borrowings under the Acquisition Credit Facilities will be reduced or repaid from the proceeds of one or more offerings of Common Shares, long-term debt securities, first preference shares or second preference shares or from amounts extended under other debt financings in order to restore the current consolidated capitalization structure of Fortis following the Acquisition. See "Use of Proceeds" and "Financing the Acquisition — Acquisition Credit Facilities".

As at December 19, 2013, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.7 billion (not including the Acquisition Credit Facilities), of which $2.2 billion was unused, including an unused amount of approximately $820 million under the Corporation's $1 billion committed revolving corporate credit facility (the "Revolving Facility"). Fortis (on a consolidated basis) intends to use the net proceeds of the first instalment under the Offering and the Concurrent Private Placement which are expected to be $563,400,000 in the aggregate (assuming no exercise of the Over-Allotment Option) to repay borrowings under the Revolving Facility and for other general corporate purposes, including financing equity requirements of the Corporation's subsidiaries. Fortis (on a consolidated basis) intends to use the net proceeds of the final instalment under the Offering and the Concurrent Private Placement which are expected to be $1,164,600,000 in the aggregate (assuming no exercise of the Over-Allotment Option) to repay borrowings under the Acquisition Credit Facilities following the closing of the Acquisition and for other Acquisition-Related Expenses. See "Use of Proceeds".

Concurrent Private Placement

The Corporation and the Selling Debentureholder have entered into subscription agreements dated December 11, 2013 pursuant to which Private Placement Subscribers will purchase on an instalment and private placement basis, Private Placement Debentures at a price of $1,000 per $1,000 principal amount of Private Placement Debentures for aggregate gross proceeds to the Selling Debentureholder of $206,000,000. The closing of the Concurrent Private Placement is scheduled to occur on the Closing Date and is subject to the concurrent closing of the Offering. Each Private Placement Subscriber will be paid a commitment fee in cash equal to $20.00 per $1,000 aggregate principal amount of Private Placement Debentures subscribed for by such Private Placement Subscriber payable on the Closing Date. In addition, Scotia Capital, RBC, TDSI and CIBC, the agents in the Concurrent Private Placement, will collectively receive an agency fee of $20.00 per $1,000 aggregate principal amount of Private Placement Debentures, payable on the Final Instalment Date, for Private Placement Debentures in respect of which the final instalment has been paid. See "Financing the Acquisition — Concurrent Private Placement".

THE OFFERING

Issuer:	Fortis Inc.
Selling Debentureholder:	FortisUS Holdings Nova Scotia Limited, a direct wholly owned subsidiary of the Corporation. See "Details of the Offering — The Selling Debentureholder".
Offering:	4.00% convertible unsecured subordinated debentures, due January 9, 2024, represented by Instalment Receipts and convertible into Common Shares at a Conversion Price of $30.72 per Common Share.
Amount:	$1,594,000,000 ($1,833,100,000 if the Over-Allotment Option is exercised in full) payable on an instalment basis.
Price:	$1,000 per $1,000 principal amount of Debentures payable on an instalment basis as follows: $333 per $1,000 principal amount of Debentures on the closing of this Offering; and $667 per $1,000 principal amount of Debentures on or before the Final Instalment Date.
Closing Date:	On or about January 9, 2014 or such other date as may be agreed upon by the Corporation, the Selling Debentureholder and the Underwriters, but not later than January 20, 2014.
Over-Allotment Option	The Selling Debentureholder has granted to the Underwriters an option, exercisable in whole or in part at any time on or prior to the 30th day following the Closing Date, to purchase additional Debentures represented by Instalment Receipts equal to up to 15% of the aggregate principal amount of Debentures represented by Instalment Receipts sold on the Closing Date, to cover over-allotments, if any. See "Plan of Distribution".
Concurrent Private Placement:	The Corporation and the Selling Debentureholder have entered into subscription agreements dated December 11, 2013 pursuant to which Private Placement Subscribers will purchase on an instalment and private placement basis, Private Placement Debentures represented by Instalment Receipts at a price of $1,000 per $1,000 principal amount of Private Placement Debentures for aggregate gross proceeds to the Selling Debentureholder of $206,000,000. The closing of the Concurrent Private Placement is scheduled to occur on the Closing Date and is subject to the concurrent closing of the Offering. Each Private Placement Subscriber will be paid a commitment fee in cash equal to $20.00 per $1,000 aggregate principal amount of Private Placement Debentures subscribed for by such Private Placement Subscriber payable on the Closing Date. In addition, Scotia Capital, RBC, TDSI and CIBC, the agents in the Concurrent Private Placement, will collectively receive an agency fee of $20.00 per $1,000 aggregate principal amount of Private Placement Debentures, payable on the Final Instalment Date, for Private Placement Debentures in respect of which the final instalment has been paid. See "Financing the Acquisition — Concurrent Private Placement".
Use of Proceeds:	The net proceeds from the Offering will be, in the aggregate, $1,528,240,000, determined after deducting the Underwriters' fee and the expenses of the Offering. In the event that the Over-Allotment Option is exercised in full, the net proceeds to be received by the Selling Debentureholder (and Fortis, on a consolidated basis) will be, in the aggregate, $1,757,776,000.

	The Selling Debentureholder intends to use the net proceeds of the Offering and of the Concurrent Private Placement to make distributions in the amounts of $1,528,240,000 (assuming no exercise of the Over-Allotment Option) and $197,760,000, respectively, to the Corporation. Fortis (on a consolidated basis) intends to use the net proceeds of the first instalment under the Offering and the net proceeds of the first instalment under the Concurrent Private Placement, which are expected to be $498,922,000 (assuming no exercise of the Over-Allotment Option) and $64,478,000, respectively, as follows: (i) to repay borrowings under the Revolving Facility, which borrowings have been incurred primarily in connection with the construction of the Waneta Expansion and financing of certain of the Corporation's subsidiaries; and (ii) for other general corporate purposes, including providing financing to the Corporation's regulated utility subsidiaries for capital expenditures. Fortis (on a consolidated basis) intends to use the net proceeds of the final instalment under the Offering and the net proceeds of the final instalment under the Concurrent Private Placement, which are expected to be $1,031,318,000 (assuming no exercise of the Over-Allotment Option) and $133,282,000, respectively, as follows: (a) to repay borrowings under the Acquisition Credit Facilities following the closing of the Acquisition; and (b) for other Acquisition-Related Expenses.
Listing and Trading:	The TSX has conditionally approved the listing of the Instalment Receipts (representing the Debentures and the Private Placement Debentures) and the Common Shares issuable on the conversion of the Debentures and Private Placement Debentures on the TSX, subject to Fortis fulfilling all of the requirements of the TSX on or before March 11, 2014. **The Corporation has no current intention to list the Debentures or the Private Placement Debentures for trading on any exchange as it currently anticipates all Debentures and Private Placement Debentures will be converted to Common Shares on the Final Instalment Date.**
Interest:	Interest on Debentures at an annual rate of 4.00% per $1,000 principal amount of Debentures will be payable quarterly in arrears in equal instalments on the first business day of March, June, September and December of each year to and including the Final Instalment Date. The first interest payment will be made on March 3, 2014 in the amount of $5.5890 per $1,000 principal amount of Debentures and will include interest payable from and including the Closing Date. Subsequently, quarterly interest payments will be made in the amount of $10.00 per $1,000 principal amount of Debentures. A final interest payment will be made on the Final Instalment Date and will be equal to the unpaid interest accrued from the date of the last quarterly interest payment to and including the Final Instalment Date. On the day following the Final Instalment Date, the interest rate payable on the Debentures will fall to an annual rate of 0% and interest will cease to accrue on the Debentures. Based on a first instalment of $333 per $1,000 principal amount of Debentures, the effective annual yield to and including the Final Instalment Date is 12.00%, and the effective annual yield thereafter is 0%. If the Final Instalment Date occurs on a day that is prior to the first anniversary of the Closing Date, holders of Debentures who have paid the final instalment on or before the Final Instalment Date will be entitled to receive, on the business day following the Final Instalment Date, in addition

	to the payment of accrued and unpaid interest to and including the Final Instalment Date, the Make-Whole Payment, being an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the Closing Date had the Debentures remained outstanding and continued to accrue interest until such date. No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the Closing Date. See "Details of the Offering — Debentures".
Conversion:	At the option of the holder, provided that payment of the final instalment has been made, each Debenture will be convertible into Common Shares on or at any time after the Final Instalment Date, but prior to the earlier of the date that the Corporation redeems the Debentures or the Maturity Date. The Conversion Price will be $30.72 per Common Share, being a conversion rate of 32.5521 Common Shares per $1,000 principal amount of Debentures, subject to adjustment in certain events. No fractional Common Shares will be issued on any conversion but in lieu thereof, the Corporation will satisfy such fractional interest by a cash payment equal to the fractional interest multiplied by the Conversion Price; provided, however, the Corporation shall not be required to make any payment of less than $10.00. A holder of Debentures who does not exercise its conversion privilege concurrently with its payment of the final instalment in order to convert its Debentures to Common Shares on the Final Instalment Date will hold a Debenture that pays 0% interest and may be redeemed by the Corporation in whole or in part on any trading day following the Final Instalment Date at a price equal to its principal amount plus any unpaid interest which accrued prior to the Final Instalment Date. See "Details of the Offering — Debentures — Conversion Right".
Instalment Payment Arrangements:	The price of $1,000 per $1,000 principal amount of Debentures is payable on an instalment basis. Prior to full payment, beneficial ownership of the Debentures will be represented by Instalment Receipts. The first instalment of $333 per $1,000 principal amount of Debentures is payable on the Closing Date. The final instalment of $667 per $1,000 principal amount of Debentures is payable on or before the Final Instalment Date. The Final Instalment Notice will set the Final Instalment Date, which shall not be less than 15 days nor more than 90 days following the date of such notice. The Final Instalment Notice shall not be provided to holders until the Approval Conditions have been satisfied. See "The Acquisition" and "The Acquisition Agreement". Each Debenture represented by an Instalment Receipt will be pledged to the Selling Debentureholder to secure the obligation of the beneficial holder to pay the final instalment in respect of such Debenture on or before the Final Instalment Date. After payment of the final instalment, the Corporation understands that each beneficial holder of Instalment Receipts will receive a customer confirmation from the registered dealer (who is a CDS participant) from or through whom it purchased the Debentures, indicating that the Debentures are no longer pledged to the Selling Debentureholder. See "Details of the Offering — Instalment Receipts — Book-Entry Only System". **If a holder of an Instalment Receipt does not pay the final instalment on or before the Final Instalment Date, the Debentures represented by such Instalment Receipt may, at the option of the Selling Debentureholder, upon compliance with applicable law and the terms of the Instalment Receipt Agreement, be forfeited to the Selling**

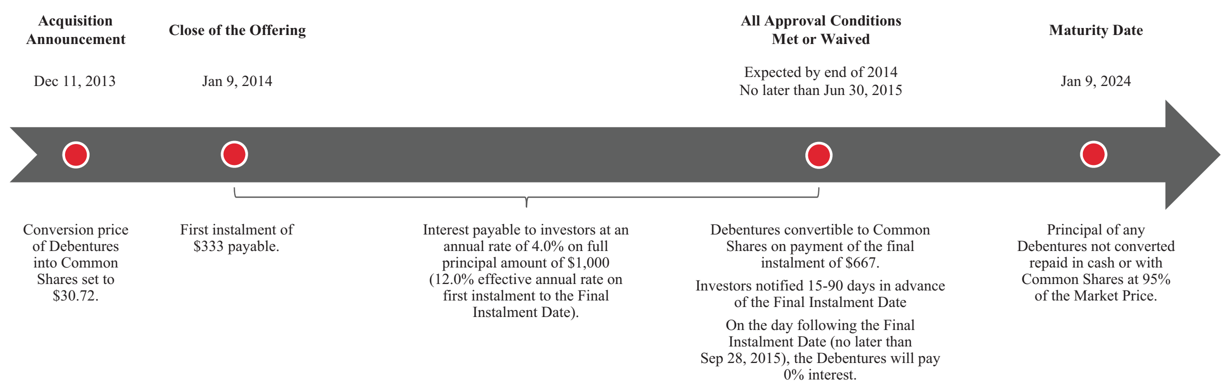
	Debentureholder in full satisfaction of the holder's obligations or such Debentures may be sold and the holder will remain liable for any deficiency in the proceeds of such sale. See "Details of the Offering — Instalment Receipts".
Rights of Instalment Receipt Holders:	Holders of Instalment Receipts will be entitled, in the manner set forth in the Instalment Receipt Agreement described herein, to fully receive payments of accrued interest and to exercise the rights of ownership attached to the Debentures represented by such Instalment Receipts unless they fail to pay the final instalment on or before the Final Instalment Date. See "Details of the Offering — Instalment Receipts — Rights and Privileges".
Redemption:	The Debentures may not be redeemed by the Corporation except that the Debentures will be redeemed by the Corporation at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the Approval Conditions will not be satisfied; (ii) termination of the Acquisition Agreement; and (iii) July 2, 2015 if the Final Instalment Notice has not been given on or before June 30, 2015. Upon any such redemption, the redemption proceeds will be paid by the Corporation to the Custodian on behalf of the holders. The Custodian will pay the following for each Debenture: (i) \$333 plus accrued and unpaid interest to the holder of the Instalment Receipt; and (ii) \$667 to the Selling Debentureholder on behalf of the holder of the Instalment Receipt in satisfaction of the final instalment. Under the terms of the Instalment Receipt Agreement, Fortis has agreed that until such time as the Debentures have been redeemed in accordance with the foregoing or the Final Instalment Date has occurred, the Corporation will at all times maintain availability under its Revolving Facility of not less than \$600,000,000 to cover one-third of the principal amount of the Debentures in the event of a mandatory redemption. After the Final Instalment Date, any Debentures not converted to Common Shares may be redeemed by the Corporation at a price equal to their principal amount plus any unpaid interest which accrued prior to the Final Instalment Date. See "Details of the Offering — Debentures — Redemption".
Maturity Date:	January 9, 2024.
Payment upon Maturity:	On the Maturity Date, the Corporation will repay the principal amount of any Debentures not converted and remaining outstanding, in cash. The Corporation may, at its option and without prior notice, satisfy the obligation to pay the principal amount of such Debentures on maturity by delivery of that number of freely tradable Common Shares obtained by dividing the principal amount of the Debentures by 95% of the Market Price. See "Details of the Offering — Debentures — Payment Upon Maturity".
Subordination	The Debentures will be direct unsecured obligations of Fortis. Payment of the principal of, interest on, any Make-Whole Payments and other amounts owing in respect of each Debenture will (i) be subordinated in right of payment to all present and future Senior Indebtedness (as defined under "Details of the Offering — Debentures — Subordination") of Fortis and (ii) rank *pari passu* with each other Debenture of the same series, including the Private Placement Debentures, (regardless of their actual date or terms of issue) and, subject to statutory preferred exceptions, with

all other present and future subordinated and unsecured indebtedness of Fortis. The trust indenture pursuant to which the Debentures and the Private Placement Debentures will be issued does not limit the ability of the Corporation to incur additional indebtedness, including indebtedness that ranks senior to the Debentures and the Private Placement Debentures, or from mortgaging, pledging, charging, hypothecating, granting a security interest in or otherwise encumbering any or all of its properties to secure any indebtedness. See "Details of the Offering — Debentures — Subordination".

Risk Factors: An investment in the Debentures represented by Instalment Receipts and the Common Shares issuable upon conversion thereof involves certain risks which should be carefully considered by prospective investors, including risks in respect of the Acquisition, the Instalment Receipts, the Debentures, the Common Shares and the post-Acquisition business and operations of the Corporation and UNS Energy. See "Risk Factors".

SUMMARY OF IMPORTANT DATES

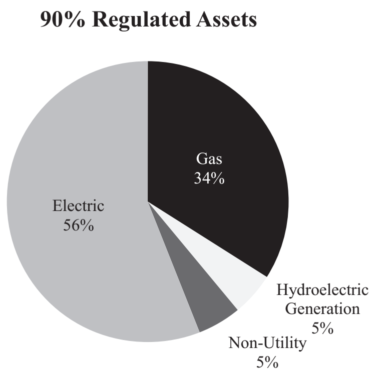
The timeline set out below outlines the important dates in respect of the Offering and the Acquisition. This timeline is for illustrative purposes only and is subject to change.

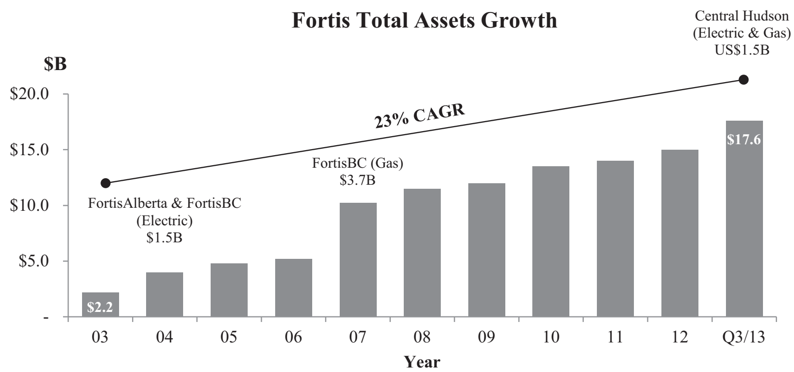


FORTIS

Fortis Inc. was incorporated as 81800 Canada Ltd. under the *Canada Business Corporations Act* on June 28, 1977. The Corporation was continued under the *Corporations Act* (Newfoundland and Labrador) on August 28, 1987 and on October 13, 1987 the Corporation amended its articles to change its name to "Fortis Inc.". The address of the head office and principal place of business of the Corporation is The Fortis Building, Suite 1201, 139 Water Street, St. John's, Newfoundland and Labrador A1B 3T2.

Fortis is the largest investor-owned gas and electric distribution utility in Canada with total assets of approximately \$17.6 billion as at September 30, 2013 and fiscal 2012 revenue (which excludes the June 2013 acquisition of CH Energy Group) totalling approximately \$3.7 billion. The Corporation serves more than 2,400,000 customers across Canada and in New York State and the Caribbean. Its regulated holdings include electric distribution utilities in five Canadian provinces, New York State and two Caribbean countries and natural gas utilities in British Columbia, Canada and New York State. As at September 30, 2013, regulated utility assets comprised approximately 90% of the Corporation's total assets, with the balance comprised of non-regulated generation assets, commercial office and retail space, hotels and petroleum supply operations. Over the last decade, total assets of Fortis have grown at a CAGR of 23%.





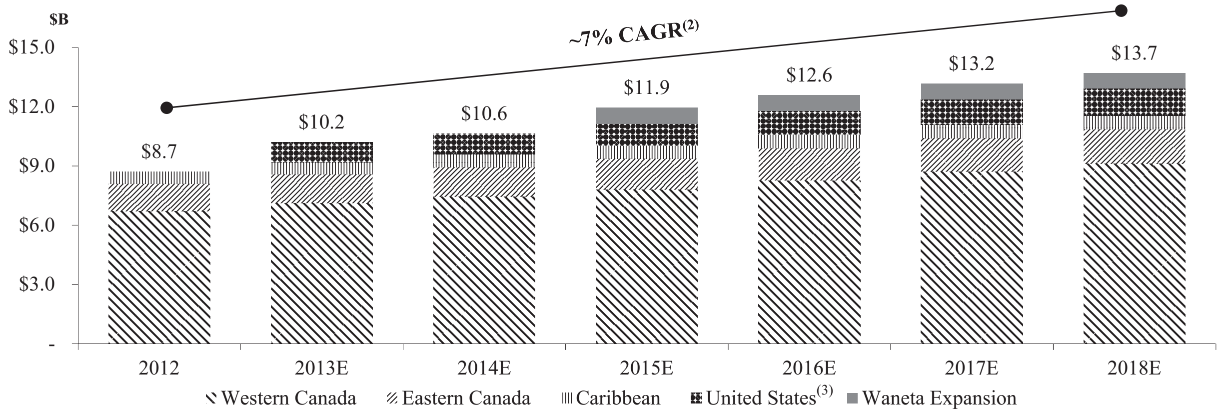
Fortis is the direct owner of all of the common shares of FortisBC Holdings, a company that, through its subsidiaries, is the principal distributor of natural gas in British Columbia. Fortis is the indirect owner of all of the common shares of FortisAlberta, a regulated electric utility that distributes electricity generated by other market participants in a substantial portion of southern and central Alberta; FortisBC, a regulated electric utility that generates, transmits and distributes electricity in the southern interior of British Columbia; Central Hudson, a regulated transmission and distribution utility serving electricity and natural gas customers in eight counties of New York State's Mid-Hudson River Valley; and Maritime Electric, the principal distributor of electricity on Prince Edward Island. Fortis also holds all of the common shares of Newfoundland Power, the principal distributor of electricity in Newfoundland. As well, through its wholly owned subsidiary FortisOntario and its subsidiaries, CNPI, Cornwall Electric and Algoma Power, Fortis provides an integrated electric utility service in Ontario to customers primarily in Fort Erie, Cornwall, Gananoque and Port Colborne and distributes electricity to customers in the district of Algoma in northern Ontario.

The Corporation's regulated electric utility assets in the Caribbean consist of its ownership, through wholly owned subsidiaries, of an approximate 60% interest in Caribbean Utilities, an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands. Fortis also owns, through a wholly owned subsidiary, Fortis Turks and Caicos, which is the principal distributor of electricity in the Turks and Caicos Islands.

The Corporation's non-regulated generation operations consist of its 100% interest in each of BECOL, FortisOntario and FortisUS Energy, as well as non-regulated generation assets owned either directly or indirectly by FortisBC and by Fortis through its 51% controlling ownership interest in the Waneta Partnership. Fortis Generation East LLP, a limited liability partnership directly held by Fortis, owns six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW.

Over the six years from 2013 through 2018, the Corporation's consolidated capital expenditure program, which is mostly funded at the individual subsidiary level and includes expenditures at Central Hudson, the Waneta Expansion and the Tilbury LNG Facility expansion, is expected to approximate $7.5 billion. Capital investment should allow the Corporation's consolidated regulated mid-year rate base, including incremental investment in rate base by Central Hudson and investment in the non-regulated Waneta Expansion, to increase at a combined CAGR of approximately 7% through 2018. Investment in energy infrastructure (rate base) to provide safe, reliable and cost-effective energy service to customers is expected to be the primary driver of earnings growth.

Mid-Year Rate Base including Waneta Expansion Investment(1)



(1) Rate base includes 100% of the Waneta Expansion Project investment (51% ownership) to be completed by Spring 2015 and Caribbean Utilities (~60% ownership).

(2) CAGR excludes the initial ~$1B rate base addition in 2013 related to the Central Hudson acquisition.

(3) Assumes C$/US$ FX rate of 1.03.

Non-utility operations are conducted through Fortis Properties and CH Energy Group. Through Fortis Properties, the Corporation owns and operates 23 hotels in eight Canadian provinces and owns approximately 2.7 million square feet of commercial office and retail space, primarily in Atlantic Canada. Non-regulated operations of CH Energy primarily consist of Griffith Energy Services, which mainly supplies petroleum products and related services to approximately 65,000 customers in the Mid-Atlantic Region of the United States.

Regulated Gas Utilities — Canadian

FortisBC Energy Companies

The natural gas distribution business of FortisBC Holdings is one of the largest in Canada. With approximately 947,000 customers as at September 30, 2013, FortisBC Holdings' subsidiaries provide service to over 96% of gas users in British Columbia. FEI is the largest of these subsidiaries, serving approximately 842,000 customers as at September 30, 2013. FEI has a service area which includes Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central interior regions of British Columbia. FEVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island and the distribution system on Vancouver Island and along the Sunshine Coast of British Columbia, serving approximately 102,000 customers as at September 30, 2013. In addition to providing transmission and distribution services to customers, FEI and FEVI also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from north-eastern British Columbia and Alberta. FEWI owns and operates the natural gas distribution system in the Resort Municipality of Whistler, British Columbia, providing service to approximately 3,000 residential and commercial customers as at September 30, 2013. Collectively, FEI, FEVI and FEWI own and operate approximately 47,000 kilometres of natural gas distribution and transmission pipelines and met a peak day demand of 1,336 TJ in 2012.

Regulated Gas & Electric Utility — United States

Central Hudson

Central Hudson, the main business of CH Energy Group, is a regulated transmission and distribution utility serving approximately 300,000 electricity and 76,000 natural gas customers in eight counties of New York State's

Mid-Hudson River Valley, as at September 30, 2013. Central Hudson's electric assets comprised approximately 78% of its total assets as at September 30, 2013 and include approximately 14,000 kilometres of distribution lines and 1,000 kilometres of transmission lines. The electric business met a peak demand of 1,168 MW in 2012. Central Hudson's natural gas assets comprised the remaining 22% of its total assets and include approximately 1,900 kilometres of distribution pipelines and more than 264 kilometres of transmission pipelines. The gas business met a peak day demand of 115 TJ in 2012. Central Hudson is subject to regulation by the New York State Public Service Commission under a traditional cost of service model.

Central Hudson primarily relies on electricity purchases from third-party providers and the New York Independent System Operator -administered energy and capacity markets to meet the demands of its full-service electricity customers. It also generates a small portion of its electricity requirements. Central Hudson purchases its gas supply requirements at various pipeline receipt points from a number of suppliers with whom it has contracted for firm transport capacity.

Regulated Electric Utilities — Canadian

FortisAlberta

FortisAlberta distributed electricity to approximately 514,000 customers in Alberta as at September 30, 2013, using approximately 116,000 kilometres of owned and/or operated distribution lines and met a peak demand of 2,652 MW in 2012. FortisAlberta's business is the ownership and operation of regulated electricity distribution facilities that distribute electricity generated by other market participants from high-voltage transmission substations to end-use customers in central and southern Alberta. FortisAlberta is not involved in the generation, transmission or direct sale of electricity.

FortisBC

FortisBC is an integrated, regulated electric utility that owns a network of generation, transmission and distribution assets located in the southern interior of British Columbia. FortisBC serves a diverse mix of approximately 163,000 customers as at September 30, 2013, with residential customers representing the largest customer segment, and met a peak demand of 737 MW in 2012. FortisBC owns four regulated hydroelectric generating plants with an aggregate capacity of 223 MW that provide approximately 45% of FortisBC's energy and 30% of its peak capacity needs. FortisBC's remaining electricity supply is acquired through long-term power purchase contracts and short-term market purchases. FortisBC's business also includes non-regulated operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generation facility owned by Teck Metals Ltd. and BC Hydro, the 149-MW Brilliant hydroelectric plant, the 120-MW Brilliant expansion plant and the 185-MW Arrow Lakes hydroelectric plant, each owned by CPC/CBT.

Newfoundland Power

Newfoundland Power is a regulated electric utility that operates an integrated generation, transmission and distribution system throughout the island portion of the Province of Newfoundland and Labrador. Newfoundland Power serves approximately 254,000 customers as at September 30, 2013, or approximately 87% of electricity consumers in the Province, and met a peak demand of 1,241 MW in 2012. Approximately 93% of the electricity that Newfoundland Power sells to its customers is purchased from Newfoundland Hydro. Newfoundland Power operates 29 small generating facilities, which generate the remaining 7% of the electricity it sells. Newfoundland Power's hydroelectric generating plants have a total capacity of 97 MW. The diesel plants and gas turbines have a total capacity of approximately 7 MW and 37 MW, respectively.

Maritime Electric

Maritime Electric is a regulated electric utility that operates an integrated generation, transmission and distribution system on Prince Edward Island. Maritime Electric directly supplies approximately 77,000 customers as at September 30, 2013, or 90% of electricity consumers on the Island, and met a peak demand of 230 MW in 2012. Maritime Electric purchases most of the energy it distributes to its customers from New Brunswick Power Corporation under various energy purchase agreements and maintains on-Island generating facilities with an aggregate capacity of 150 MW.

FortisOntario

FortisOntario's regulated distribution operations serve approximately 64,000 customers in the Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario as at September 30, 2013, and met a combined peak demand of 253 MW in 2012. FortisOntario's operations are comprised of CNPI, Cornwall Electric and Algoma Power. Through CNPI, FortisOntario owns international transmission facilities at Fort Erie and owns a 10% interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies that, together, serve approximately 38,000 customers as at September 30, 2013.

Regulated Electric Utilities — Caribbean

Caribbean Utilities

Fortis holds an indirect approximate 60% controlling ownership interest in Caribbean Utilities. Caribbean Utilities has the exclusive right to distribute and transmit electricity on the island of Grand Cayman, Cayman Islands, pursuant to a 20-year licence entered into on April 3, 2008. Caribbean Utilities also entered into a non-exclusive 21.5-year power generation licence with the Government of the Cayman Islands on April 3, 2008. Caribbean Utilities serves approximately 27,000 customers as at September 30, 2013, has approximately 151 MW of installed diesel-powered generating capacity and met a peak demand of 96 MW in 2012. The Class A Ordinary Shares of Caribbean Utilities are listed for trading on the TSX under the symbol CUP.U.

Fortis Turks and Caicos

Both of the Fortis Turks and Caicos utilities are integrated electric utilities, which collectively serve approximately 12,000 customers, or approximately 98% of electricity consumers on the Turks and Caicos Islands as at September 30, 2013. The utilities met a combined peak demand of approximately 35 MW in 2012. Fortis Turks and Caicos owns and operates approximately 600 kilometres of transmission and distribution lines. Fortis Turks and Caicos is the principal distributor of electricity on Turks and Caicos pursuant to 50-year licences that expire in 2036 and 2037.

Expropriated Assets — Belize Electricity

Until June 20, 2011, Fortis held an indirect approximate 70% controlling ownership interest in Belize Electricity, the regulated principal distributor of electricity in Belize, Central America. On June 20, 2011, the GOB enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity. The consequential loss of control over the operations of the utility resulted in the Corporation discontinuing the consolidation method of accounting for Belize Electricity, effective June 20, 2011. The Corporation has classified the book value of the previous investment in Belize Electricity as a long-term other asset on the consolidated balance sheet. As at September 30, 2013, the long-term other asset, including foreign exchange impacts, totalled $105 million.

In October 2011 Fortis commenced an action in the Belize Supreme Court to challenge the legality of the expropriation of its investment in Belize Electricity and court proceedings with respect to the matter are continuing. Fortis commissioned an independent valuation of its expropriated investment in Belize Electricity and submitted its claim for compensation to the GOB in November 2011. The GOB also commissioned a valuation of Belize Electricity and communicated the results of such valuation in its response to the Corporation's claim for compensation. The fair value determined under the GOB's valuation is significantly lower than the fair value determined under the Corporation's valuation and the book value of Belize Electricity.

In July 2012 the Belize Supreme Court dismissed the Corporation's claim of October 2011. Also in July 2012, Fortis filed its appeal of the above-noted trial judgment in the Belize Court of Appeal. The appeal was heard in October 2012 and a decision is pending. Any decision of the Belize Court of Appeal may be appealed to the Caribbean Court of Justice, the highest court of appeal available for judicial matters in Belize. There can be no assurances that a settlement with the GOB will be reached or that any appeal will be successful. Fortis believes it has a strong, well-positioned case before the Belize courts supporting the unconstitutionality of the expropriation. There exists, however, a reasonable possibility that the outcome of the litigation may be unfavourable to the Corporation and the amount of compensation otherwise to be paid to Fortis under the legislation expropriating Belize Electricity could be lower than the book value of the Corporation's expropriated investment in Belize Electricity.

Non-Regulated — Fortis Generation

Belize

Non-regulated generation operations in Belize are conducted through BECOL under a franchise agreement with the GOB. BECOL owns and operates the 25-MW Mollejon hydroelectric generating facility, the 7-MW Chalillo hydroelectric generating facility and the 19-MW Vaca hydroelectric generating facility. All such facilities are located on the Macal River in Belize. These hydro plants generate average annual energy production of approximately 240 GWh. BECOL sells its entire output to Belize Electricity under 50-year power purchase agreements expiring in 2055 and 2060. In October 2011, the GOB purportedly amended the Constitution of Belize to require majority government ownership of three public utility providers, including Belize Electricity, but excluding BECOL, but there can be no assurance that it will not change its intentions. The GOB has also indicated it has no intention to expropriate BECOL. Fortis continues to control and consolidate the financial statements of BECOL.

Ontario

Non-regulated generation operations of FortisOntario are comprised of the operation of a 5-MW gas-powered cogeneration plant in Cornwall. All thermal energy output of this plant is sold to external third parties, while the electricity output is sold to Cornwall Electric. Fortis Generation East LLP owns and operates six small hydroelectric generating facilities in eastern Ontario with a combined capacity of 8 MW. The electricity produced from these facilities is sold to the Ontario Power Authority, via the Hydroelectric Contract Initiative, under fixed-price contracts.

British Columbia

Non-regulated generation operations in British Columbia, conducted through FortisBC, include the 16-MW run-of-river Walden hydroelectric power plant near Lillooet that sells its entire output to BC Hydro under a contract set to expire in the fourth quarter of 2013. Accordingly, FortisBC is exposed to the risk that it will not be able to sell the power from this facility beyond 2013 on similar terms.

In October 2010, the Corporation formed the Waneta Partnership with CPC/CBT and concluded definitive agreements to construct the 335-MW Waneta Expansion at an estimated cost of approximately $900 million. The facility is situated adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia. CPC/CBT are both 100% owned entities of the Government of British Columbia. Fortis owns a controlling 51% interest in the Waneta Partnership and, through FortisBC, will operate and maintain the Waneta Expansion when it comes into service, which is currently expected in spring 2015. SNC-Lavalin Group Inc. was awarded a contract for approximately $590 million to design and build the Waneta Expansion. Construction began in November 2010 and capital expenditures of approximately $534 million have been incurred on this capital project through September 30, 2013. Key construction activities for year-to-date 2013 include the ongoing civil construction of the powerhouse and intake, installation of the turbine components, installation of ancillary mechanical and electrical powerhouse services, and most notably, the encapsulating of the scrollcase in concrete. The Waneta Expansion will be included in the Canal Plant Agreement (as described in the Corporation's AIF) and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing hydrologic risk associated with the project. The energy output, approximately 630 GWh, and associated capacity required to deliver such energy from the Waneta Expansion will be sold to BC Hydro under an executed long-term energy purchase agreement. The surplus capacity, equal to 234 MW on an average annual basis, is expected to be sold to FortisBC under a long-term capacity purchase agreement. In November 2011, FortisBC executed the agreement to purchase the capacity from the Waneta Expansion and filed such executed agreement with the BCUC. The form of the agreement was originally accepted for filing by the BCUC in September 2010. In May 2012, the BCUC determined that the executed agreement was in the public interest and a hearing was not required. The agreement has been accepted for filing as an energy supply contract and FortisBC has been directed by the BCUC to develop a rate-smoothing proposal. A rate-smoothing deferral mechanism has been included as part of FortisBC's 2014-2018 PBR revenue requirements application, which was filed on July 5, 2013 and updated on October 18, 2013, and is currently subject to review by the BCUC.

Upstate New York

Non-regulated generation assets in Upstate New York State are owned and operated by FortisUS Energy and include four hydroelectric generating stations with a combined generating capacity of approximately 23 MW operating under licences from FERC. All four hydroelectric generating facilities sell energy at market rates through purchase agreements with Niagara Mohawk Power Corporation.

Non-Regulated — Non-Utility

Through Fortis Properties, the Corporation owns and operates 23 hotels, comprised of more than 4,400 rooms, in eight Canadian provinces and owns approximately 2.7 million square feet of commercial office and retail space, primarily in Atlantic Canada. Non-regulated operations of CH Energy Group primarily consist of Griffith Energy Services, which mainly supplies petroleum products and related services to approximately 65,000 customers in the Mid-Atlantic Region of the United States.

RECENT DEVELOPMENTS

Completion of the Acquisition of CH Energy Group

On February 20, 2012, Fortis entered into an agreement to acquire all of the outstanding common shares of CH Energy Group for US$65.00 per share in cash, for an aggregate purchase price of approximately US$1.5 billion, including the assumption of US$518 million of debt on closing. On June 27, 2013, Fortis completed the acquisition of CH Energy Group. The net purchase price of the acquisition of CH Energy Group (the "CH Energy Acquisition") of approximately $1,019 million (US$972 million) was financed through the issuance of 18,500,000 Common Shares, pursuant to the conversion of Subscription Receipts concurrently with the closing of the CH Energy Acquisition for net proceeds of approximately $567 million after tax, with the balance of the purchase price being initially funded through drawings under the Revolving Facility.

Issuance of First Preference Shares, Series K

On July 18, 2013, Fortis issued 10,000,000 4.00% Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series K for gross proceeds of $250,000,000. The proceeds were used to redeem all of the Corporation's 5.45% First Preference Shares, Series C on July 10, 2013 for $125 million, to repay a portion of credit facility borrowings and for other general corporate purposes.

Long-Term Debt Offerings

On September 13, 2013, FortisAlberta issued 30-year $150,000,000 unsecured debentures at 4.85%. The proceeds of the debt offering are being used to repay credit facility borrowings, to fund future capital expenditures and for general corporate purposes.

On November 8, 2013, Newfoundland Power issued 30-year $70,000,000 first mortgage bonds at 4.805%. The proceeds of the debt offering were used to repay credit facility borrowings incurred primarily to fund capital expenditures and for general corporate purposes.

Debt Offering by Fortis

On October 1, 2013, Fortis issued US$285,000,000 3.84% senior unsecured notes, series C due October 1, 2023 and US$40,000,000 5.08% senior unsecured notes, series D due October 1, 2043. The proceeds of the debt offering were used to repay a portion of the Corporation's U.S. dollar-denominated borrowings under the Revolving Facility, which borrowings were used to fund the CH Energy Acquisition and for general corporate purposes.

Tilbury LNG Facility Expansion

On November 28, 2013, the Government of British Columbia announced its approval of an investment of up to $400 million by FEI to expand its LNG plant on Tilbury Island in Delta, British Columbia (the "Tilbury LNG Facility") to provide LNG to transportation customers as a cleaner alternative to diesel. The expansion is expected to include a second storage tank and new liquefier, both of which are expected to be in service by mid-2016. The current Tilbury LNG Facility can liquefy 130,000 cubic metres of natural gas per day. Following the expansion that capacity is expected to increase to as much as 1.69 million cubic metres a day. The storage capacity at Tilbury will also increase from the current equivalent of 17 million cubic metres of natural gas to more than 40 million cubic metres.

The Government of British Columbia has exempted the Tilbury LNG facility expansion from the requirement to obtain a certificate of public convenience and a necessity review by the BCUC. The commencement of construction of the expansion remains subject to approval of the FEI board and the B.C. Oil and Gas Commission, but the required zoning approval for the expansion has already been obtained.

FortisAlberta Capital Tracker Application

On December 6, 2013 the AUC released its decision in response to a 2013 capital tracker application (the "Capital Tracker Application") filed by, among others, FortisAlberta in connection with the PBR of utility companies in the Province of Alberta.

While the AUC's decision provides that the Capital Tracker Application meets certain of the criteria established under the PBR, the Capital Tracker Application requires that detailed capital-tracking calculations on a project-by-project basis and additional forecast information for certain projects be submitted. FortisAlberta will re-submit its Capital Tracker Application by May 15, 2014 including the required calculations, and until such time as the AUC releases its decision on the basis of the re-submitted calculations, FortisAlberta is entitled to the existing capital tracking recovery approved by the AUC on March 4, 2013.

Credit Rating Reviews

On December 11, 2013, following the announcement of the Acquisition, DBRS placed the Corporation's issuer rating, unsecured debt rating and preferred share ratings of A (low) 'under review with developing implications'. This action reflects DBRS' view that the proposed Acquisition would have a modestly negative impact on the Corporation's business risk profile, while the impact on the financial risk profile is uncertain since the financing plan for the Acquisition has not been finalized. DBRS will further review the Corporation's financing plan when it is finalized.

In addition, on December 12, 2013, S&P revised its outlook on the Corporation to negative from stable following the announcement of the Acquisition on the basis of its expectation that the Acquisition would be financed primarily using the Debentures and the Private Placement Debentures, which will depress key credit metrics of the Corporation until the conversion thereof to Common Shares. S&P has also revised from stable to negative its outlook on the credit ratings of the Corporation's subsidiaries FortisAlberta, Maritime Electric and Caribbean Utilities using its group rating methodology. S&P has revised from stable to positive its outlook on TEP and has confirmed the long-term 'A-' credit rating of Fortis and the 'BBB' long-term credit rating of TEP.

Labour Relations Matters

On December 16, 2013, the IBEW Local 213 accepted the binding interest arbitration offer of FortisBC. As a result, FortisBC employees that are members of the IBEW Local 213 returned to work. The collective agreement between FortisBC and the IBEW Local 213 expired on January 31, 2013 and negotiations between the parties had been ongoing since January 2013. The IBEW Local 213 served the company 72 hours' strike notice on March 13, 2013 and commenced partial job action on May 16, 2013. Prior to December 16, 2013, FortisBC had been operating under the most recent essential services order issued by the Labour Relations Board of British Columbia in September 2013. Binding interest arbitration is an established labour practice which empowers a neutral, third-party arbitrator to resolve the outstanding issues between the parties. The binding interest arbitration process between FortisBC and the IBEW Local 213 will begin at a later date and will result in a new collective agreement. Approximately 200 of FortisBC's employees are members of the IBEW Local 213.

THE ACQUISITION

Overview

On December 11, 2013, Fortis and certain subsidiaries of Fortis entered into the Acquisition Agreement with UNS Energy which provides for, among other things, the Acquisition by an indirect wholly owned subsidiary of Fortis of all of the issued and outstanding common shares of UNS Energy and the merger of the acquiring subsidiary of Fortis into UNS Energy. The aggregate purchase price for the Acquisition is approximately US$4.3 billion, comprised of approximately US$2.5 billion in cash on closing and the assumption of approximately US$1.8 billion of debt. The

Acquisition is subject to receipt of UNS Energy common shareholder approval and certain regulatory and governmental approvals, including approval by each of the ACC and FERC and the satisfaction of customary closing conditions. The closing of the Acquisition is currently expected to occur by the end of 2014.

UNS Energy, formerly UniSource Energy Corporation, is a utility services holding company headquartered in Tucson, Arizona engaged through its subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona. UNS Energy's fiscal 2012 operating revenue totalled approximately US$1.5 billion and, as at September 30, 2013, UNS Energy had total assets of approximately US$4.3 billion. Based on *pro forma* financial information as at September 30, 2013, following the Acquisition, the Corporation's total assets will increase by approximately 33.5% to approximately $23.5 billion. The Acquisition of UNS Energy is expected to increase the Corporation's consolidated rate base by approximately US$3.0 billion by 2015 and its total customers by approximately 654,000. Following the Acquisition, the regulated utility subsidiaries of Fortis will serve more than 3,000,000 customers.

UNS Energy Overview

UNS Energy has three direct and indirect subsidiaries which are regulated utilities: TEP, UNS Gas and UNS Electric. UNS Energy's utility operations are vertically integrated with generation, transmission and distribution being regulated by either the ACC or FERC.

TEP is a vertically integrated regulated electric utility and is UNS Energy's largest and principal operating subsidiary, representing approximately 84% of the total assets as at September 30, 2013 and approximately 81% of the operating revenues of UNS Energy for the nine months ended September 30, 2013. TEP was incorporated in the State of Arizona in 1963 and currently generates, transmits and distributes electricity to approximately 412,000 retail electric customers in southern Arizona. TEP's service territory covers 1,155 square miles (2,991 square kilometres) and includes a population of approximately 1,000,000 people in the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells electricity to other entities in the western United States.

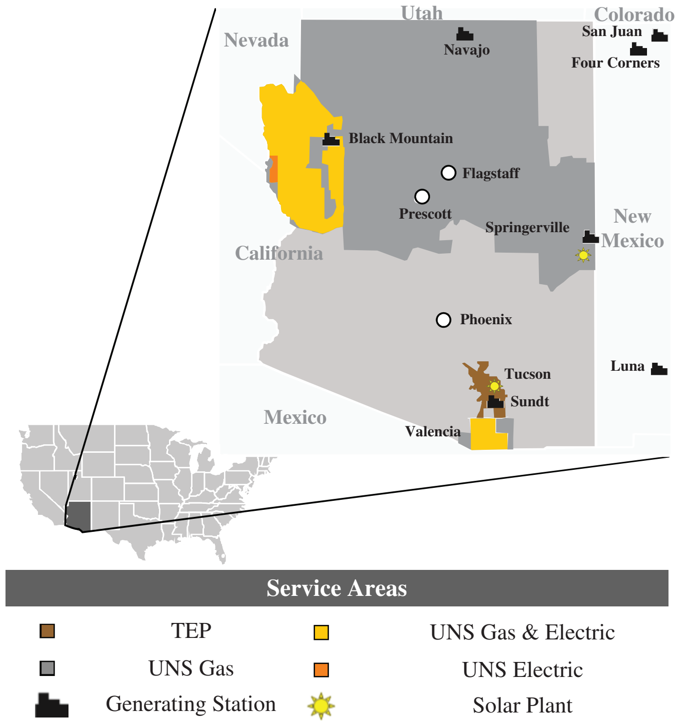
UNS Gas is a regulated gas distribution company serving approximately 149,000 retail customers in northern Arizona's Mohave, Yavapai, Coconino and Navajo counties, as well as Santa Cruz County in southern Arizona. These counties, with a combined population of approximately 700,000, comprise approximately 50% of the territory in the State of Arizona. UNS Gas represented approximately 7% of the total assets of UNS Energy as at September 30, 2013 and approximately 8% of the operating revenues of UNS Energy for the nine months ended September 30, 2013.

UNS Electric is a vertically integrated regulated electric utility company serving approximately 93,000 retail customers in Arizona's Mohave and Santa Cruz counties. These counties have a combined population of approximately 250,000. UNS Electric represented approximately 9% of the total assets of UNS Energy as at September 30, 2013 and approximately 11% of the operating revenues of UNS Energy for the nine months ended September 30, 2013.

The non-regulated business of UNS Energy, which comprises less than 1% of UNS Energy's total assets, includes the operations of Millennium and UniSource Energy Development Company. SES, a wholly owned subsidiary of Millennium, provides electrical contracting and meter reading services in Arizona, as well as other services at Springerville.

The following map depicts the service territories and generating stations of UNS Energy and its regulated utility subsidiaries. See “The Acquired Business”.

UNS Energy Utility Service Areas



Acquisition Rationale

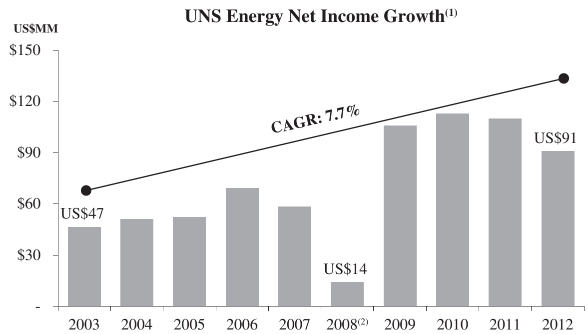
The business operated by UNS Energy is attractive to Fortis for the following reasons:

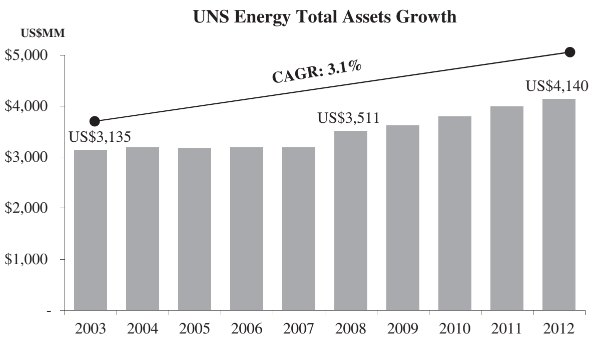
Accretive to Earnings per Common Share in the First Full Year

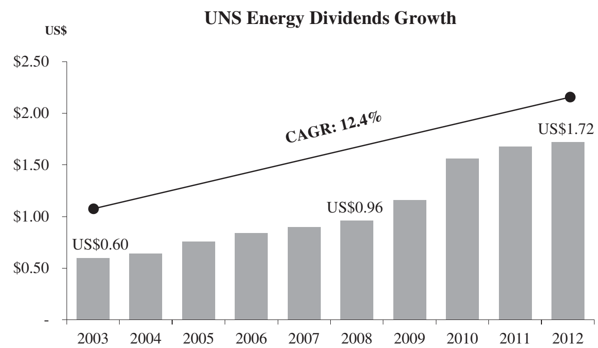
Management expects that the Acquisition will be accretive to the Corporation’s earnings per Common Share in the first full year following its completion, excluding one-time Acquisition-Related Expenses. See “The Acquisition Agreement” and “The Acquired Business”.

Acquisition of a Well-Run Utility

Over the past 10 years (through 2012), UNS Energy has (i) increased net income by a CAGR of 7.7%, (ii) increased total assets by a CAGR of 3.1% and (iii) increased annual dividends per common share from US$0.60 to US$1.72. Key drivers of earnings growth include the 2013 TEP Rate Order, which is primarily related to prior infrastructure investment, and the expiration and buyout of the Springerville Unit 1 Leases.





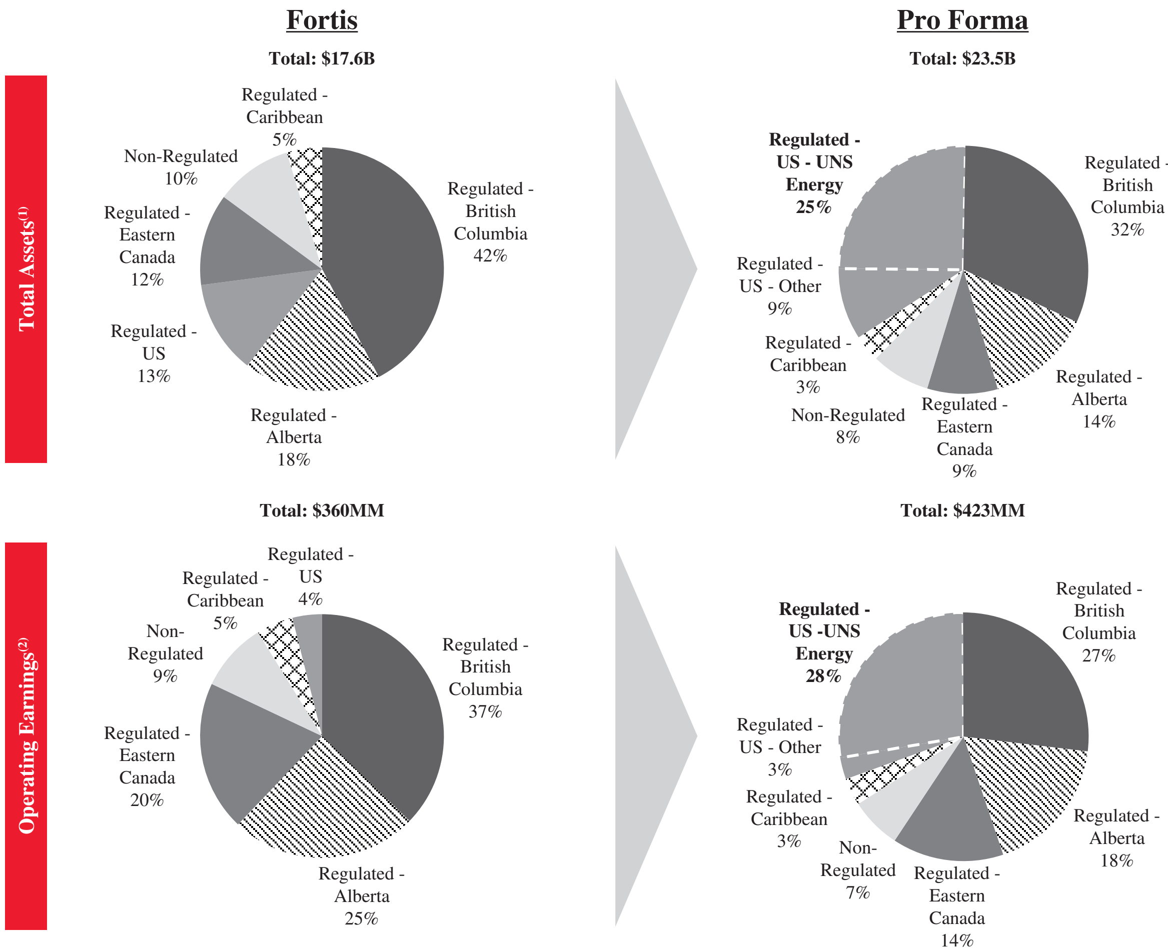


(1) Net income excludes the effect of extraordinary accounting changes and earnings from discontinued operations.

(2) UNS Energy's 2008 net income was reduced due to a US$58 million deduction of revenue for an over-collection of competitive transition charges, which the ACC ordered to be returned to customers, as well as higher fuel and purchased power costs, which prior to January 1, 2009 had not been collected from customers through a flow-through mechanism.

Diversification of Regulated Earnings Base

UNS Energy represents a significant opportunity for Fortis to further diversify its regulated assets, earnings base and cash flows and improve the risk profile of Fortis by diversifying its geographic reach and providing Fortis with a more economically diverse portfolio of assets. The increased diversification to, and growth in, the Corporation's regulated assets, earnings and cash flows is consistent with the Corporation's strategy of pursuing accretive acquisition opportunities both in the United States and Canada.



(1) As at September 30, 2013.

(2) For the 9-month period ended September 30, 2013. Operating earnings of Fortis excludes the $22 million extraordinary gain on settlement of expropriation matters associated with the Exploits River Hydro Partnership.

Supportive Regulatory Environment

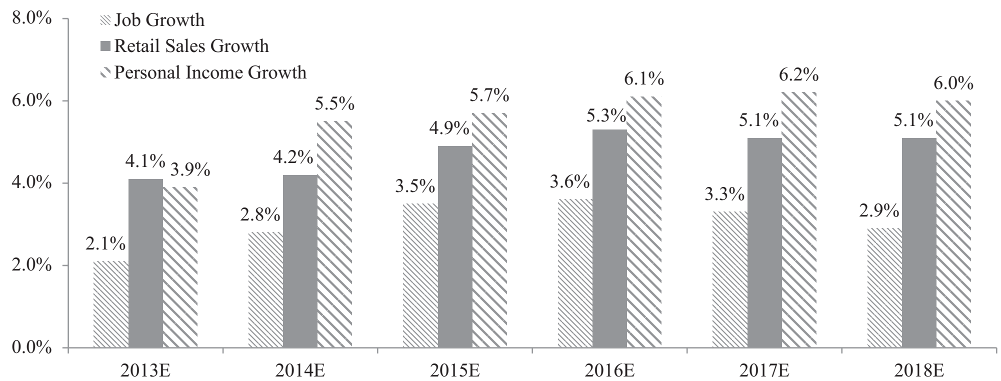
UNS Energy operates within a supportive regulatory environment. The regulated utility rates for retail electric and natural gas service are determined by the ACC on a "cost of service" basis with rate design structures that pass through costs related to fuel, purchased power, environmental compliance, energy efficiency and distributed generation. Most of the ACC's regulatory components were recently ranked as "Excellent" or "Very Good" by DBRS in its Regulatory Framework for Utilities report dated October 2013. The 2013 TEP Rate Order allows for 10.0% ROE on 43.5% common equity.

Favourable Arizona Economic Drivers

Arizona is a state in the southwestern region of the United States with a population of approximately 6.5 million, making it the 15th most populous of the 50 states of the United States. The largest employer in the State is the public service, with copper mining being the State's largest single industry. Copper mined in the state of Arizona accounts for two-thirds of the copper output of the United States.

Additionally, the Arizona economy continues to generate solid economic growth, with job growth at 2.0% over the past year, above the national rate of 1.6%. According to the University of Arizona Economic and Business Research Centre, growth in jobs, retail sales and personal income is expected to reach 2.9%, 5.1% and 6.0%, respectively, by 2018, providing a base of support for future utility earnings. Job growth in Arizona is expected to continue at an annual rate of 1.8% over the next 30 years, reaching 4.3 million jobs by 2043.

Arizona Economic Forecast (1)



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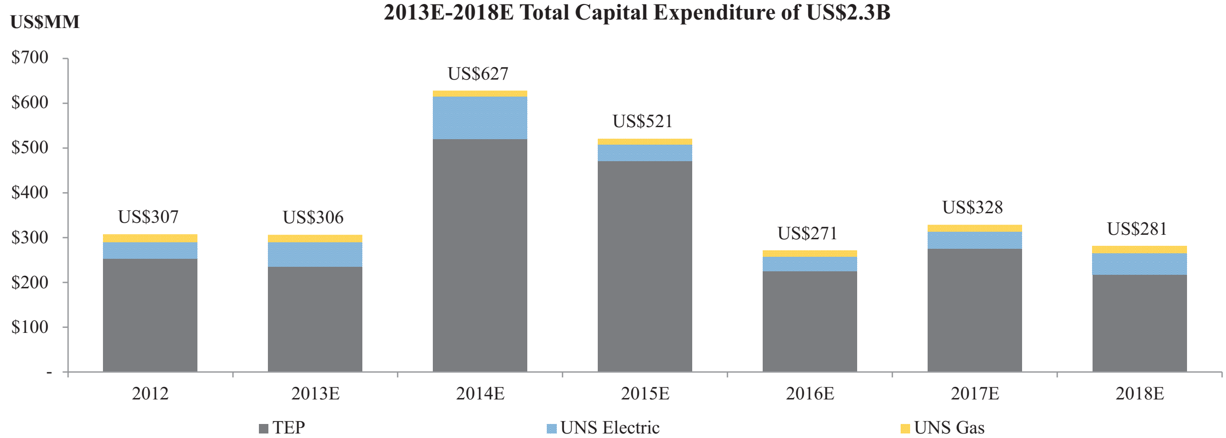
(1) Source: University of Arizona Economic and Business Research Centre, October 2013.

Rate Base Growth

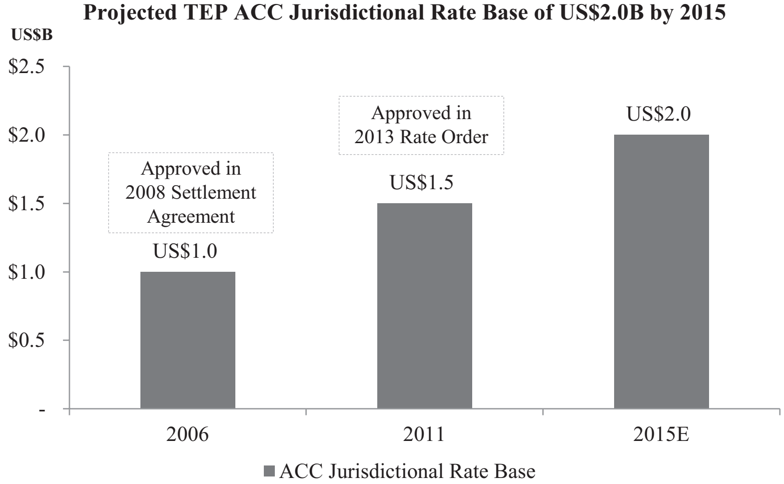
UNS Energy's continued investment in its electric and gas businesses to provide safe, reliable and cost-efficient energy service to its customers is expected to result in attractive rate base growth. UNS Energy has forecasted that capital investment will total approximately US$2.3 billion over the period from 2013 to 2018. UNS Energy's rate base is expected to reach US$3.0 billion by 2015 and to grow at a CAGR of approximately 7% through 2018.

2013E-2018E Total Capital Expenditure of US$2.3B



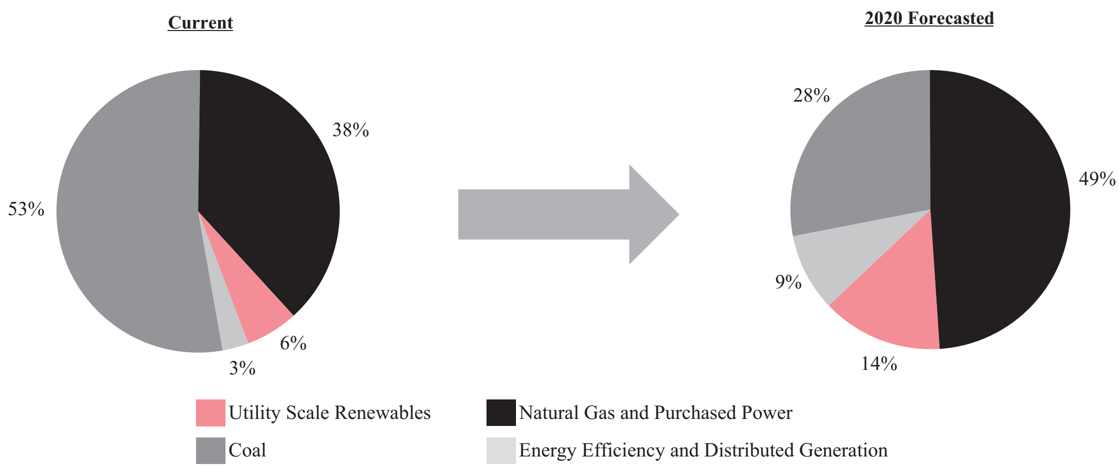
TEP projects that its ACC jurisdictional rate base will increase to approximately US$2.0 billion by 2015 (from an ACC approved 2011 rate base of US$1.5 billion). This is expected to increase UNS Energy's total rate base to approximately US$3.0 billion by 2015.

Projected TEP ACC Jurisdictional Rate Base of US$2.0B by 2015



TEP expects to invest significant capital into diversifying its generation fleet, including through the anticipated purchase of the natural gas-fired combined-cycle Gila River Unit 3 generation plant (with a capacity of 550 MW) and utility scale renewables generation. Renewables investments will diversify TEP's generation resources, as well as assist TEP in the mitigation of environmental impact.

TEP Generation Capacity Mix



Experienced Management Team

UNS Energy is a well-run utility with an experienced management team committed to providing customers with safe, reliable and cost-effective energy service. Over the last five years, UNS Energy customers have experienced, on average, approximately one outage for a duration of 1.5 hours per year. Management has decreased debt-to-capitalization of UNS Energy from 84% in 2000 to 62% as at September 30, 2013, resulting in a four notch upgrade to TEP's credit rating over the period to Baa2 (Moody's). Management has also demonstrated strong regulatory expertise, completing each of the past three rate cases in approximately one year on average.

Paul J. Bonavia was appointed Chairman and Chief Executive Officer of UNS Energy, TEP and UniSource Energy Services by UNS Energy's board of directors on January 1, 2009. Prior to joining UNS Energy, Mr. Bonavia served as the President of Xcel Energy's Commercial Enterprises business unit and the President of its Energy Markets unit. David Hutchens was named President and Chief Operating Officer of UNS Energy, TEP and UniSource Energy Services in December 2011 after serving as an Executive Vice President since March 2011 and was appointed to UNS

Energy's board of directors in December 2013. Mr. Hutchens joined TEP in July 1995 and has held various management positions overseeing wholesale energy sales. Mr. Hutchens graduated from the University of Arizona with a bachelor's degree in aerospace engineering and a master's degree in business administration with an emphasis in finance.

See "The Acquired Business", "The Acquisition Agreement", "Risk Factors — Risk Factors Relating to the Acquisition" and "Special Note Regarding Forward-Looking Statements".

Utility Management Approach of Fortis

The Corporation's approach to utility management is based on creating value for customers that ultimately translates into long-term value for shareholders. Fortis structures its operations as separate operating companies in each jurisdiction. Focused local management teams have the benefit of access to the utility management experience and expertise of Fortis. The senior management team of UNS Energy, which Fortis expects to retain, will add valuable operational expertise in electric generation and distribution and natural gas distribution to the existing expertise of Fortis in such areas. This approach allows local managers to build relationships with, and be responsive to, both customers and regulators. Fortis recognizes that regulation is a key aspect of its core business and has developed a disciplined, cost-conscious asset investment and operating philosophy which is responsive to regulation.

The management of Fortis has substantial experience in integrating newly acquired enterprises into the Fortis group. In 2013, Fortis acquired CH Energy Group and has successfully integrated its businesses into the Fortis group. In 2007, Fortis acquired FortisBC Holdings (formerly Terasen Inc.) and has successfully integrated the natural gas distribution business of the FortisBC Energy companies into the Fortis group. Fortis also successfully integrated FortisBC (formerly, Aquila Networks Canada (British Columbia) Ltd.) and FortisAlberta (formerly, Aquila Networks Canada (Alberta) Ltd.) into the Fortis group following their acquisition in 2004.

THE ACQUIRED BUSINESS

UNS Energy

UNS Energy, formerly UniSource Energy Corporation, is a utility services holding company headquartered in Tucson, Arizona engaged through its subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona. The common stock of UNS Energy trades on the NYSE under the symbol "UNS".

UNS Energy has three direct and indirect subsidiaries which are regulated utilities, TEP, UNS Gas and UNS Electric. The percentage of UNS Energy's total assets, operating revenues and net income by regulated utility subsidiary for the nine months ended September 30, 2013 was as follows:

Percentage of UNS Energy
(Nine Months Ended September 30, 2013)

Subsidiary	Total Assets	Operating Revenues	Net Income
TEP	84%	81%	85%
UNS Electric	9%	11%	10%
UNS Gas	7%	8%	5%

Revenues of each of TEP and UNS Electric include revenues from retail electricity sales and wholesale electricity sales made primarily from power generated at facilities owned or leased by TEP or UNS Electric, as applicable. In addition, TEP receives income from its transmission assets and its operation of Springerville Units 3 and 4 for Tri-State and SRP, respectively. UNS Gas' revenues primarily arise from retail and wholesale gas sales. The following table sets forth the total operating revenue of UNS Energy by source, for each of 2011, 2012 and the nine month period ended September 30, 2013.

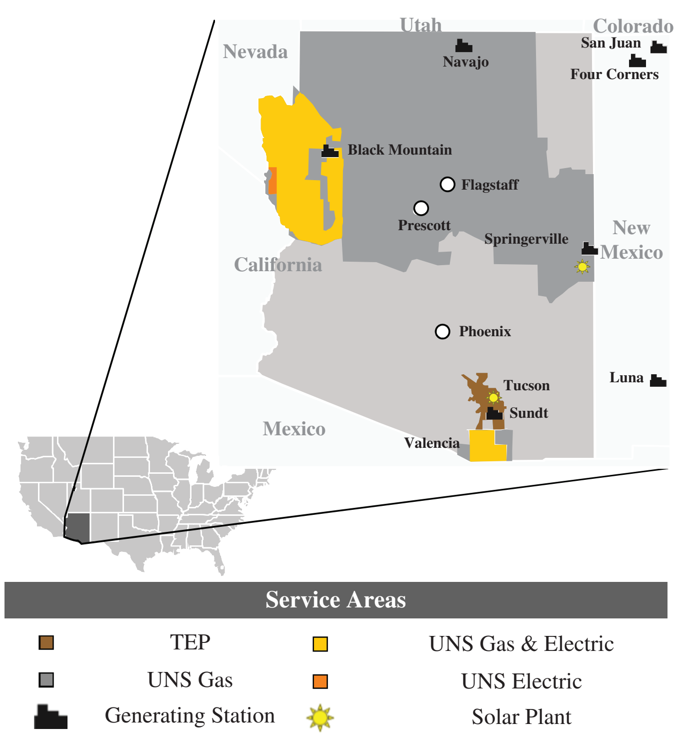
	Nine Months ended September 30, 2013	Years ended December 31,	
		2012	2011
	(thousands of U.S. dollars)	(thousands of U.S. dollars)	
Operating Revenues			
Electric Retail Sales	$ 868,523	$1,087,279	$1,085,822
Electric Wholesale Sales	92,581	125,414	132,346
Gas Revenue	86,432	123,133	145,053
Other Revenues	86,863	125,940	115,481
Total Operating Revenues	$1,134,399	$1,461,766	$1,478,702

For further information on the financial condition and results of UNS Energy, reference is made to the audited consolidated financial statements of UNS Energy as of December 31, 2012 and 2011, including the consolidated statements of income and cash flows for each of the years ended December 31, 2012, 2011 and 2010, and the unaudited consolidated financial statements of UNS Energy for the three and nine months ended September 30, 2013, each of which is included in this Prospectus.

UNS Energy Service Territory

UNS Energy's regulated utility subsidiaries service approximately 654,000 retail customers in Arizona. The following map depicts the service territories and generating stations of UNS Energy and its regulated utility subsidiaries.

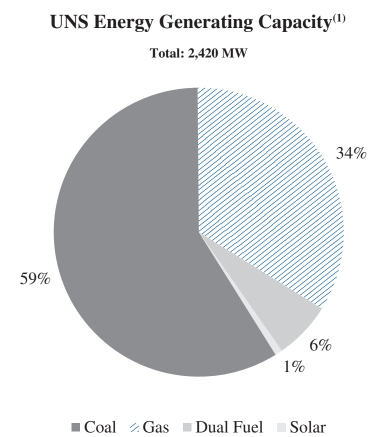
UNS Energy Utility Service Areas

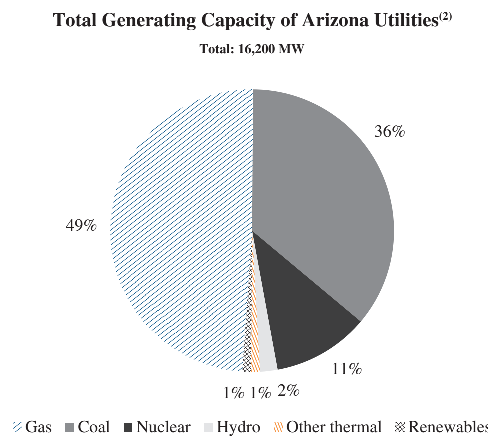


UNS Energy Generation Profile

UNS Energy currently owns or leases generation resources with an aggregate capacity of 2,420 MW, including 19 MW of solar capacity. As shown in the chart which follows, 59% of UNS Energy's generating capacity is fueled by coal. The aggregate generating capacity of Arizona's utilities is 16,200 MW, 36% of which is fueled by coal.

UNS Energy and Arizona Generation Capacity Mix





(1) Owns 2,074 MW, including TEP's 14% ownership of the 401-MW Springerville Unit 1 Plant, and leases an additional 346 MW.

(2) Source: Energy Information Association. Arizona utilities include UNS Energy, Salt River Power Project, Arizona Electric Power Cooperative and Arizona Public Service.

TEP

TEP is a vertically integrated, regulated electric utility and UNS Energy's largest and principal operating subsidiary, representing approximately 84% of the total assets as at September 30, 2013 and approximately 81% of the operating revenues of UNS Energy for the nine months ended September 30, 2013. TEP was incorporated in the State of Arizona in 1963 and currently generates, transmits and distributes electricity to approximately 412,000 retail electric customers in southern Arizona. TEP's service territory covers 1,155 square miles (2,991 square kilometres) and includes a population of approximately 1,000,000 people in the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP has sufficient generating capacity which, together with existing power purchase agreements and expected generation plant additions, should satisfy the requirements of its customer base and meet expected future peak demand requirements. In addition, TEP sells electricity to other entities in the western United States.

Peak Demand

Peak demand occurs during the summer months due to the cooling requirements of TEP's retail customers. Retail peak demand varies from year-to-year due to weather, economic conditions, and other factors. TEP's retail peak demand declined over the period of 2008 to 2012 due primarily to weak economic conditions and the implementation of energy efficiency programs. TEP experienced peak demand of 2,290 MW in 2012. TEP believes its existing generation capacity, together with power purchase agreements and expected generation plant additions will be sufficient to meet future demand.

Retail Customers

TEP provides electric utility service to a diverse group of residential, commercial, industrial and public sector customers. Retail sales accounted for 78.8% of TEP's operating revenues in 2012. In 2012, 41% of TEP's energy sales were to residential customers, 21% were to commercial customers, 23% were to non-mining industrial customers, 12% were to mining customers and 3% were to public entities. In 2013, the retail energy consumption by customer class is expected to be similar to the historical customer distribution. Major industries served include copper mining, cement manufacturing, defense, health care, education, military bases and other governmental entities. Two of TEP's largest single customers are in the copper mining industry. Sales to these two customers increased by 0.9% in 2012 and 0.3% in 2011 as a result of increased production due to high copper prices, but are not expected to materially increase in 2013 or 2014. TEP's retail sales are influenced by several factors, including economic conditions, seasonal weather patterns, DSM initiatives and the increasing use of energy efficient products and opportunities for customers to generate their own electricity.

Local, regional and national economic factors have impacted the growth in the number of customers in TEP's service territory. In 2012, 2011 and 2010, TEP's average number of retail customers increased by less than 1% year over year. During the past three years, economic conditions in the State of Arizona and state requirements for energy efficiency and distributed generation have negatively affected TEP's retail electricity sales. TEP's retail sales volumes in 2012 were approximately 9,265 GWh or 1.1% below 2009 sales volumes.

Although the Retail Electric Competition Rules established in 1999 ("Rules") by the ACC, which regulates portions of TEP's utility accounting practices and energy rates, contemplated that TEP's retail customers may be eligible to choose an alternative energy service provider ("ESP"), portions of those Rules have been invalidated by the Arizona courts and there are currently no ESPs authorized to provide alternative retail electric service to TEP's customers. See "The Acquired Business — Regulation — Retail Electric Competition Rules".

Wholesale Business

TEP's electric utility operations include the wholesale marketing of electricity to other utilities and power marketers in the southwestern United States. Wholesale sales transactions are made on both a firm and interruptible basis and accounted for 8.3% of TEP's total 2012 operating revenues. A firm contract requires TEP to supply power on demand (except under limited emergency circumstances), while an interruptible contract allows TEP to stop supplying power in specific circumstances. See "The Acquired Business — TEP — Generating and Other Resources".

Generally, TEP commits to future sales with third parties based on expected excess generating capability, forward prices and generation costs, using a diversified portfolio approach to provide a balance between long-term, mid-term and spot energy sales. TEP's wholesale sales consist primarily of long-term or short term sales.

Long-Term Sales

Long-term wholesale sales contracts cover periods of more than one year. TEP typically uses its own generation to serve the requirements of its long-term wholesale customers. In 2012, 26% of TEP's wholesale revenues, or approximately 2% of TEP's total 2012 operating revenues, were attributable to long-term wholesale sales contracts. TEP's material long-term wholesale power supply contracts are described below:

- Through May 2016, SRP is required to purchase 500,000 MWh of on-peak energy per year from TEP.
- TEP has a contract with the NTUA which expires in December 2022. TEP serves the portion of NTUA's load that is not served by the authority's allocation of federal hydroelectric power. Over the last three years, sales to NTUA averaged 225,000 MWh per year.

Short-Term Sales

Short-term forward contracts commit TEP to sell a specified amount of capacity or energy at a specified price over a given period of time, typically for one-month, three-month or one-year periods. TEP also engages in short-term sales by selling energy in the daily or hourly markets at fluctuating spot market prices and making other non-firm energy sales. In 2012, 74% of TEP's operating revenues from wholesale sales, or approximately 6% of TEP's total 2012 operating revenues, were attributable to short-term sales. All revenues from short-term wholesale sales offset fuel and purchased power costs and are passed through to TEP's retail customers. TEP uses short-term wholesale sales as part of its hedging strategy to reduce customer exposure to fluctuating power prices. In addition, 10% of profits from wholesale trading activity is passed through to TEP's retail customers.

Generating and Other Resources

At December 31, 2012, TEP had owned electrical generating capacity of 1,921 MW and leased electrical generating capacity of 346 MW, for total net generating capacity of 2,267 MW, as set forth in the table below. Several of the generating assets in which TEP has an interest are jointly owned. In the United States large power generation facilities are often developed by partnerships or joint ventures of different utilities to assist with financing the large capital expenditures required in connection with the construction of such facilities. See “Risk Factors — Risk Factors Relating to the Post-Acquisition Business and Operations of the Corporation and UNS Energy — Jointly-owned generating plants and generating plants operated by third parties”.

TEP Sources of Net Generating Capacity

Generating Source	Unit No.	Location	Date In Service	Resource Type	Net Capability MW	Operating Agent	TEP's Share %	TEP's Share MW
Springerville Station (1)	1	Springerville, AZ	1985	Coal	401	TEP	100.0	401
Springerville Station	2	Springerville, AZ	1990	Coal	403	TEP	100.0	403
Springerville Station (2)	3	Springerville, AZ	2005	Coal	400	TEP	0.0	0
Springerville Station (2)	4	Springerville, AZ	2009	Coal	400	TEP	0.0	0
San Juan Station	1	Farmington, NM	1976	Coal	340	PNM	50.0	170
San Juan Station	2	Farmington, NM	1973	Coal	340	PNM	50.0	170
Navajo Station	1	Page, AZ	1974	Coal	750	SRP	7.5	56
Navajo Station	2	Page, AZ	1975	Coal	750	SRP	7.5	56
Navajo Station	3	Page, AZ	1976	Coal	750	SRP	7.5	56
Four Corners Station	4	Farmington, NM	1969	Coal	784	APS	7.0	55
Four Corners Station	5	Farmington, NM	1970	Coal	784	APS	7.0	55
Luna Generating Station	1	Deming, NM	2006	Gas	555	PNM	33.3	185
Sundt Station	1	Tucson, AZ	1958	Gas/Oil	81	TEP	100.0	81
Sundt Station	2	Tucson, AZ	1960	Gas/Oil	81	TEP	100.0	81
Sundt Station	3	Tucson, AZ	1962	Gas/Oil	104	TEP	100.0	104
Sundt Station	4	Tucson, AZ	1967	Coal/Gas	156	TEP	100.0	156
Sundt Internal Combustion Turbines		Tucson, AZ	1972-1973	Gas/Oil	50	TEP	100.0	50
DeMoss Petrie		Tucson, AZ	1972	Gas/Oil	75	TEP	100.0	75
North Loop		Tucson, AZ	2001	Gas	95	TEP	100.0	95
Springerville Solar Station		Springerville, AZ	2002-2010	Solar	6	TEP	100.0	6
Tucson Solar Projects		Tucson, AZ	2010-2012	Solar	12	TEP	100.0	12
Total TEP Capacity (3)								2,267

(1) 14.1% owned and 85.9% of generating capacity under lease as of September 30, 2013. As of January 2015 the capacity received by TEP from Springerville Unit 1 will be reduced to 49.5% of its continuous operating capability. See “The Acquired Business — TEP —Generating and Other Resources — Springerville Generating Station”.

(2) Springerville Units 3 and 4 are operated by TEP, but are owned by Tri-State and SRP, respectively. These facilities are located at the same site as Springerville Units 1 and 2. The owners of Springerville Units 3 and 4 compensate TEP for operating the facilities and pay an allocated portion of the fixed costs related to the Springerville Common Facilities and the Springerville Coal Handling Facilities. TEP is not entitled to any net generating capacity from Springerville Units 3 and 4.

(3) Excludes 683 MW of additional resources, which consist of certain capacity purchases and interruptible retail load.

Springerville Generating Station

TEP currently owns a 14.1% undivided interest in Unit 1 of the coal-fired Springerville and leases the remaining 85.9%. Springerville Unit 2 is owned by San Carlos Resources, Inc. (“San Carlos”), a wholly owned subsidiary of TEP. Springerville Units 3 and 4 are owned by Tri-State and SRP, respectively. TEP operates all four Springerville generating units, and Tri-State and SPR compensate TEP for operating the facilities. TEP is not entitled to any net generating capacity from Springerville Units 3 and 4.

TEP’s other interests in Springerville include leasehold interests in the Springerville Coal Handling Facilities and the facilities at Springerville used in common by all four Springerville units (“Springerville Common Facilities”). In

1984, TEP sold and leased back the Springerville Coal Handling Facilities and has since purchased a 13% ownership interest therein. The terms of the Springerville Coal Handling Facilities leases ("Springerville Coal Handling Facilities Leases") expire in April 2015 but have fixed-rate renewal options if certain conditions are satisfied, as well as a fixed-price purchase provision of US$120 million. TEP has agreed with Tri-State, the lessee of Springerville Unit 3, and SRP, the owner of Springerville Unit 4, that if the Springerville Coal Handling Facilities Leases are not renewed, TEP will exercise the purchase options under these contracts. Upon such purchase, SRP will be obligated to buy a portion of the Springerville Common Facilities and Tri-State will be obligated to either buy a portion of the Springerville Common Facilities or continue making payments to TEP for the use of its facilities.

TEP's lease arrangement relating to Springerville Unit 1 and an undivided one-half interest in certain Springerville Common Facilities ("Springerville Unit 1 Leases"), expire in 2015 but contain optional fair market value renewal and purchase provisions. In August and October 2013, TEP exercised purchase options with respect to an additional aggregate 35.4% undivided interest in Springerville Unit 1 from the owner participants at an aggregate purchase price of approximately US$65.5 million, with the closing of the lease purchase options scheduled to occur in December 2014 and January 2015. In 2015, following TEP's acquisition of the additional 35.4% interest in Springerville Unit 1 and the expiry of the Springerville Unit 1 Leases, TEP's share of the continuous operating capability of Springerville Unit 1 will be reduced to 49.5%. TEP has indicated that it does not intend to acquire an ownership interest in Springerville Unit 1 that is greater than 50% due to its intention to reduce its exposure to coal generation.

TEP's lease arrangements relating to an undivided one-half interest in certain Springerville Common Facilities ("Springerville Common Facilities Leases"), which expire in 2017 and 2021, have optional fair market value renewal options as well as a fixed-price purchase provision. The fixed prices to acquire the interest in the Springerville Common Facilities currently leased by TEP are US$38 million in 2017 and US$68 million in 2021.

Sundt Station and Sundt Internal Combustion Turbines

TEP owns and operates the Sundt Internal Combustion Turbines and all four units of the Sundt Generating Station (the "Sundt Station") located near Tucson, Arizona. The Sundt Internal Combustion Turbines have a net generating capacity of 50 MW. Sundt Station Units 1, 2 and 3 can be operated on either natural gas or diesel oil and have a net generating capacity of 81 MW, 81 MW and 104 MW, respectively. Sundt Station Unit 4 can be operated on either natural gas or coal and has a net generating capacity of 156 MW. The Sundt Station and the Sundt Internal Combustion Turbines are designated as "must-run generation" facilities. Must-run generation units are required to run in certain circumstances to maintain distribution system reliability and to meet local load requirements. See "The Acquired Business — Environmental Regulation — Regional Haze Rules — Sundt".

Purchases and Interconnections

To supplement its leased and owned net generating capacity, TEP purchases power from other utilities and power marketers. TEP may enter into contracts: (a) to purchase energy under long-term contract to serve retail load and long-term wholesale contracts; (b) to purchase capacity or energy during periods of planned outages or for peak summer load conditions; and (c) to purchase energy for resale to certain wholesale customers under load and resource management agreements.

TEP typically uses generation from its gas-fired units, supplemented by power purchases, to meet the summer peak demands of its retail customers. Some of these power purchase agreements ("PPAs") are price-indexed to natural gas prices. Due to its increasingly seasonal gas and purchased power usage, TEP hedges a portion of its total natural gas exposure with fixed price contracts for a maximum of three years. TEP also purchases energy in the daily and hourly markets to meet higher than anticipated demands, to cover unplanned generation outages or when doing so is more economical than running owned generation.

TEP is a member of a regional reserve-sharing organization and has reliability and power sharing relationships with other utilities. These relationships allow TEP to call upon other utilities during emergencies, such as plant outages and system disturbances, and reduce the amount of power reserves TEP is required to carry.

As a result of the *Energy Policy Act of 2005*, owners and operators of bulk power transmission systems, including TEP, are subject to mandatory reliability standards that are developed and enforced by NERC and subject to the oversight of FERC. TEP periodically reviews its operating policies and procedures to ensure continued compliance with these standards.

Renewable Energy Resources

As of December 31, 2012, TEP owned 18 MW of photovoltaic ("PV") solar generating capacity. The Springerville solar system, which is located near Springerville, has a total capacity of 6 MW. TEP's remaining 12 MW of PV solar generating capacity is located in the City of Tucson.

In order to meet the ACC's renewable energy requirements which, among other things, require TEP, UNS Electric and other affected utilities to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements in 2025, TEP has PPAs for 125 MW of capacity from solar resources, 50 MW of capacity from wind resources and 2 MW of capacity from a landfill gas generation plant. As of December 31, 2012, approximately 74 MW of solar resources and 50 MW of wind resources contracted by TEP were operational. The remaining resources contracted by TEP are expected to be developed over the next several years. The solar PPAs contain options that would allow TEP to purchase all or part of the related project at a future period. See "The Acquired Business — Regulation — Renewable Energy Standard and Tariff".

Future Generating Resources

TEP is evaluating several energy resource options, including coal, natural gas and renewables for future use to satisfy its power requirements. The focus of TEP's long-term energy resource diversification strategy is to provide long-term rate stability for customers, mitigate environmental impacts, comply with regulatory requirements and leverage existing utility infrastructure. TEP is gradually reducing its reliance on coal generation over time by increasing the capacity of efficient combined-cycle gas turbines and renewables, particularly by adding solar generating capacity, and expects coal to represent less than 50% of generating capacity by 2020. TEP will add generating resources and/or transmission import capability to meet forecasted retail and firm wholesale load demands. TEP's ACC approved 2013 RES implementation plan includes an investment of US$28 million for company-owned solar projects. TEP is emerging as an industry leader in the development and support of renewable energy and was named 2012 Investor Owned Utility of the Year by the Solar Electric Power Association. In addition, in August 2013, TEP entered into exclusive negotiations with Entegra to purchase the Gila River, Unit 3 Generating Station ("Gila River") in Gila Bend, Arizona. Gila River is a natural gas-fired combined-cycle unit with a capacity rating of 550 MW, which went into service in 2003. UNS Electric may purchase up to 150 MW of Gila River Unit 3, while TEP would purchase the remaining capacity. The anticipated purchase of Gila River is consistent with TEP's strategy to diversify its generation fuel mix and gradually reduce its reliance on coal. See "The Acquired Business — TEP — Fuel Supply".

Gila River will replace foregone coal-fired leased capacity following expiry of the Springerville Unit 1 Leases and the expected reduction of coal-fired generating capacity from San Juan Unit 2, which may be retired on or before December 31, 2017. See "The Acquired Business — Environmental Regulation — Regional Haze Rules — San Juan". TEP expects to execute a definitive purchase agreement with Entegra by the end of 2013 and close the purchase transaction in late 2014 subject to final agreement on terms and, among other things, receipt of required regulatory approvals. TEP expects to finance the anticipated acquisition of Gila River using its revolving credit facility and bridge financing and expects to ultimately refinance such indebtedness with equity injections and the issuance of long-term debentures.

Fuel Supply

TEP's fuel cost and usage information for the three most recently completed calendar years are:

	Average Cost per MMBtu Consumed by TEP			Percentage of Total Btu Consumed by TEP		
	2012	**2011**	**2010**	**2012**	**2011**	**2010**
Coal	$2.44	$2.42	$2.23	88%	92%	90%
Gas	$3.92	$5.20	$4.69	12%	8%	10%
All Fuels	$2.63	$2.65	$2.47	100%	100%	100%

Coal

TEP's principal fuel for electric generation is low-sulfur, bituminous or sub-bituminous coal from mines in Arizona, New Mexico and Colorado. In 2012, 88% of the energy sold or used by TEP was generated from coal, down from 92% in 2011 and 90% in 2010. In 2012, 72% of the total power generated by TEP was generated from coal. More than 90% of TEP's coal supply is purchased under long-term contracts, which results in more predictable prices. TEP's average cost per tonne of coal, including transportation, was US$45.84 in 2012, US$46.64 in 2011 and US$41.99 in 2010. The following table sets forth the supplier, the contract expiration date and the amount of coal consumed in 2012 for TEP's coal generating stations in respect of which coal was purchased under a long-term supply contract:

Generating Station	Coal Supplier	2012 Coal Consumption (thousands of tonnes)	Contract Expiration
Springerville	Peabody Coalsales	3,287	2020
Four Corners	BHP Billiton	400	2016
San Juan	San Juan Coal Co.	1,098	2017
Navajo	Peabody Coalsales	475	2019

TEP is the operator and sole owner (or lessee) of the Springerville Units 1 and 2 (see "The Acquired Business — TEP — Generating and Other Resources — Springerville Generating Station") and Sundt Unit 4 coal-fired generation plants. The coal supplies for Springerville Units 1 and 2 are transported approximately 200 miles by railroad from northwestern New Mexico. TEP expects its contracted coal reserves to be sufficient to supply the estimated requirements for Springerville Units 1 and 2 for their presently estimated remaining lives.

The coal supplies for Sundt Unit 4 are transported approximately 1,300 miles by railroad from Colorado. Prior to 2010, Sundt Unit 4 was predominantly fueled by coal; however, the generating station can also be operated using natural gas. Both fuels are combined with methane, a renewable energy resource, piped in from a nearby landfill. Since 2010, TEP has fueled Sundt Unit 4 with both coal and natural gas depending on which resource is most economic. In 2013, TEP has fueled Sundt Unit 4 with coal from inventory. TEP does not expect to encounter any issues in sourcing coal for use in Sundt Unit 4 in the future, to the extent that coal is used as the fuel for this generator.

TEP also participates in jointly-owned coal-fired generating facilities at the Four Corners Generating Station ("Four Corners"), the Navajo Generating Station ("Navajo") and the San Juan Generating Station ("San Juan"). Four Corners, which is operated by Arizona Public Service ("APS") and San Juan, which is operated by Public Service Company of New Mexico ("PNM") are mine-mouth generating stations located adjacent to the coal reserves used in those generating plants. Navajo, which is operated by SRP, obtains its coal supply from a nearby coal mine with a dedicated rail delivery system. The coal supplies used at Four Corners, Navajo and San Juan are under long-term contracts administered by the operating agents. TEP expects coal reserves available to these three jointly-owned generating facilities to be sufficient for the remaining presently estimated lives of the generating stations. See also "The Acquired Business — Environmental Regulation — Regional Haze Rules" and "Risk Factors — Risk Factors Relating to the Post-Acquisition Business and Operations of the Corporation and UNS Energy".

Natural Gas Supply

TEP typically uses generation from its natural gas-fueled facilities, in addition to energy from its coal-fired facilities and purchased power, to meet the summer peak demands of its retail customers and local reliability needs. TEP purchases gas from Southwest Gas Corporation under a retail tariff for its North Loop generating station's 95 MW of internal combustion turbines and receives distribution service under a transportation agreement for its DeMoss Petrie generating station, a 75 MW internal combustion turbine. TEP purchases capacity from EPNG for transportation from the San Juan and Permian Basins to its Sundt plant under a contract effective through 2018. TEP also buys gas from third-party suppliers for the Sundt and DeMoss Petrie generating stations.

TEP purchases gas transportation for the Luna Generating Station ("Luna") from EPNG from the Permian Basin to the plant site under an agreement effective through January 2017, with right-of-first-refusal for continuation thereafter. TEP purchases gas for its share of Luna from various suppliers in the Permian Basin region.

Transmission Access

TEP has transmission access and power transaction arrangements with over 120 electric systems or suppliers. TEP also has various ongoing projects that are designed to increase access to the regional wholesale energy market and improve the reliability, capacity and efficiency of its existing transmission and distribution systems. In 2012, 1.4% of TEP's operating revenue was derived from TEP's transmission assets.

Employees

On September 30, 2013, TEP had 1,398 employees, of which approximately 49% are represented by the IBEW Local No. 1116. A new collective bargaining agreement between the IBEW Local No. 1116 and TEP was entered into in January 2013 and expires in January 2016.

UNS Gas

UNS Gas is a regulated, gas distribution company serving approximately 149,000 retail customers in northern Arizona's Mohave, Yavapai, Coconino and Navajo counties, as well as Santa Cruz County in southern Arizona. These counties, with a combined population of approximately 700,000, comprise approximately 50% of the territory in the State of Arizona. UNS Gas represented approximately 7% of the total assets of UNS Energy as at September 30, 2013 and approximately 8% of the operating revenues of UNS Energy for the nine months ended September 30, 2013.

The customer base of UNS Gas is primarily residential with sales to residential customers providing approximately 58% of the total revenues of UNS Gas in 2012. UNS Gas' annual retail customer growth rate was less than 1% from 2010 through 2012. UNS Gas typically records peak demand during the winter months when cooler weather leads to heating demand. Accordingly, UNS Gas typically records the majority of its net income during the first and fourth quarters.

Gas Supply and Transmission

UNS Gas directly manages its gas supply and transportation contracts. The market price for gas varies based upon the period during which the commodity is purchased and is affected by weather, supply issues, the economy and other factors. UNS Gas hedges its gas supply prices by entering into fixed price forward contracts and financial swaps at various times during the year to ensure more stable prices for its customers. These purchases and hedges are made up to three years in advance with the goal of hedging at least 45% of the expected monthly gas consumption with fixed prices prior to the beginning of each month.

UNS Gas buys most of the gas it distributes from the San Juan Basin. The gas is delivered on the EPNG and Transwestern Pipeline Company ("Transwestern") interstate pipeline systems under firm transportation agreements with combined capacity sufficient to meet the demands of the customers of UNS Gas.

With EPNG, the average daily capacity right of UNS Gas is approximately 655,000 therms per day, with an average of 1,095,000 therms per day in the winter season (November through March) to serve its northern and southern Arizona service territories. UNS Gas has capacity rights of 250,000 therms per day on the San Juan Lateral and Mainline of the Transwestern pipeline. The Transwestern pipeline principally delivers gas to the portion of the UNS Gas distribution system serving customers in Flagstaff and Kingman and also the Griffith Power Plant in Mohave County.

UNS Gas signed a separate agreement with Transwestern for transportation capacity rights on the Phoenix Lateral Extension Line that expires in 2024. The average daily capacity right of UNS Gas on such line is 126,100 therms per day, with an average of 221,900 therms per day in the winter season.

Employees

On September 30, 2013, UNS Gas had 183 employees, of which 107 employees were represented by IBEW Local No. 1116 and 5 employees were represented by IBEW Local No. 387. The agreements with the IBEW Local No. 1116 and No. 387 expire in June 2015 and February 2014, respectively. Negotiations for a new collective bargaining agreement with IBEW Local No. 387 are scheduled to begin in January 2014.

UNS Electric

UNS Electric is a regulated, vertically integrated electric utility company serving approximately 93,000 retail customers in Arizona's Mohave and Santa Cruz counties as at September 30, 2013. These counties have a combined population of approximately 250,000. UNS Electric represented approximately 9% of the total assets of UNS Energy as of September 30, 2013 and approximately 11% of the operating revenues of UNS Energy for the nine months ended September 30, 2013.

UNS Electric's customer base is primarily residential, with some commercial and industrial customers. Peak demand met by UNS Electric for 2012 was 437 MW. UNS Electric's annual retail customer growth rate was less than 1% from 2010 through 2012. UNS Electric typically records the majority of its net income during the second and third quarters when hot weather contributes to higher energy consumption.

Power Supply and Transmission

UNS Electric relies on a portfolio of long, intermediate and short-term purchases to meet customer load requirements. In addition, UNS Electric has generating resources which in 2012 met 152 MW or 35% of its 2012 peak demand.

Generating Resources

UNS Electric owns and operates the Black Mountain Generating Station ("BMGS"), a 90 MW gas-fired facility located near Kingman, Arizona. In July 2011, UNS Electric purchased BMGS from UNS Energy's subsidiary UniSource Energy Development Company. UNS Gas purchases and transports natural gas to BMGS for UNS Electric under long-term natural gas transportation and sales agreements.

UNS Electric also owns and operates the Valencia Power Plant ("Valencia"), located in Nogales, Arizona. Valencia consists of four gas and diesel-fueled combustion turbine units and provides approximately 62 MW of peaking resources. The Valencia facility is directly interconnected with the distribution system serving the city of Nogales and the surrounding areas.

In addition, if the Gila River purchase is successfully completed, UNS Electric will receive its proportionate share of the power generated annually at such facility.

Renewable Energy Resources

UNS Electric has agreed to purchase the output of a combined wind farm and solar generating facility located near Kingman, which is comprised of 10 MW of wind and 0.5 MW of solar. The above-market cost of energy purchased through the 20-year PPA will be recovered through the Renewable Energy Standard ("RES") surcharge. See "The Acquired Business — Regulation — Renewable Energy Standard and Tariff". UNS Electric also invested US$6 million in 2012 in company-owned solar PV capacity and expects to make similar annual solar energy investments in the near future.

Transmission

UNS Electric imports the power generated at BMGS into its Mohave County and Santa Cruz County service territories over Western Area Power Administration's ("WAPA") transmission lines. UNS Electric has transmission service agreements with WAPA for its transmission capacity that expire in June 2016. UNS Electric is upgrading its existing 115 kV transmission line serving Santa Cruz County to 138 kV to improve service reliability. This upgrade is expected to be completed by October 2014 and is included in UNS Electric's current capital expenditures forecast.

Employees

On September 30, 2013, UNS Electric had 145 employees, of which 27 were represented by IBEW Local No. 387 and 88 were represented by IBEW Local No. 769. The existing agreement with IBEW Local No. 387 expires in February 2014, with negotiations for a new collective bargaining agreement scheduled to begin in January 2014. The existing agreement with IBEW Local No. 769 expires in June 2016.

Other Non-Regulated Segments

The non-regulated businesses of UNS Energy, which comprises less than 1% of UNS Energy's total assets, include the operations of Millennium and UniSource Energy Development Company. SES, a wholly owned subsidiary of Millennium, provides electrical contracting and meter reading services in Arizona, as well as other services at Springerville. On September 30, 2013, SES had 266 employees, of which 233 are represented by IBEW Local No. 1116 and 20 by IBEW Local No. 570. The collective bargaining agreement with IBEW Local No. 1116 expires in December 2014. The collective bargaining agreement with IBEW Local No. 570 expires in May 2016.

Regulation

The ACC is a regulatory body governed by the Arizona state constitution and is composed of five elected commissioners. Commissioners are elected state-wide for staggered four-year terms and are limited to serving a total of two terms.

The ACC regulates portions of TEP, UNS Gas and UNS Electric's utility accounting practices and energy rates. The ACC has authority over rates charged to retail customers, the siting of generation and transmission facilities, the issuance of securities and transactions with affiliated parties. The regulated utility rates for retail electric and natural gas service are determined by the ACC on a cost of service basis. Retail rates as set by the ACC are designed to provide recovery of allowable operating expenses and an opportunity to earn a reasonable return on rate base. Rate base is generally determined by reference to the original cost (net of depreciation) of utility plant in service, and to various adjustments for deferred taxes and other items, plus a working capital component. Over time, additions to utility plant in service increase rate base while depreciation of utility plant reduces rate base. The rates charged to retail customers by TEP, UNS Gas and UNS Electric also include pass-through mechanisms that allow each utility to recover the actual prudently incurred costs of its fuel, transmission and energy purchases to serve retail customers. FERC regulates the terms and prices of transmission services and wholesale electricity sales, wholesale transport and purchases of natural gas and portions of the accounting practices of TEP, UNS Gas and UNS Electric. As generators of electricity, each of TEP and UNS Electric have FERC tariffs to sell power at market-based rates.

Renewable Energy Standard and Tariff

The ACC's RES requires TEP, UNS Electric and other affected utilities to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements in 2025. Affected utilities must file annual RES implementation plans for review and approval by the ACC. The approved cost of carrying out those plans is recovered from retail customers through the RES surcharge. Any RES surcharge collections above or below the costs incurred to implement the plans are deferred and reflected in the financial statements of the utility as a regulatory asset or liability. Both TEP and UNS Electric have complied with the RES implementation plans filed by each such utility with the ACC to date. TEP and UNS Electric expect to meet the 2013 renewable energy target of 4% of retail kWh sales.

Electric Energy Efficiency Standards and Decoupling

In August 2010, the ACC approved new Electric Energy Efficiency Standards ("Electric EE Standards") designed to require TEP, UNS Electric and other affected electric utilities to implement cost-effective programs to reduce customers' energy consumption. In 2012, the Electric EE Standards targeted total kWh savings of 3% of 2011 retail kWh sales; in 2013, the Electric EE Standards target total kWh savings of 5% of 2012 retail kWh sales. The Electric EE Standards increase annually thereafter up to a targeted cumulative annual reduction in retail kWh sales of 22% by 2020. The programs adopted by TEP and UNS Electric in 2011 and 2012 to comply with Electric EE Standards saved cumulative energy as of December 31, 2012 equal to approximately 2.5% of their respective 2011 retail kWh sales.

New and existing DSM programs, direct load control programs and energy efficient building codes are acceptable means to meet the Electric EE Standards as set forth by the ACC. The Electric EE Standards provide for the recovery of costs incurred to implement DSM programs. DSM programs, and the rates charged to customers for such programs, are subject to annual review and approval by the ACC.

In 2010, the ACC issued a policy statement recognizing the need to adopt rate decoupling or another mechanism to make Arizona's Electric EE Standards viable. A decoupling mechanism is designed to encourage energy conservation by restructuring utility rates to separate the recovery of fixed costs from the level of energy consumed. The 2013 TEP Rate Order and the September 2013 UNS Electric settlement agreement with ACC staff, which was approved by the ACC on December 17, 2013, include rate decoupling mechanisms. See "The Acquired Business — Rates — TEP" and "The Acquired Business — Rates — UNS Electric".

Gas Energy Efficiency Standards and Decoupling

In 2010, the ACC approved Gas Energy Efficiency Standards ("Gas EE Standards") which are designed to require UNS Gas and other affected utilities to implement cost-effective DSM programs. In 2012, the Gas EE Standards targeted total retail therm savings equal to 1.2% of 2011 sales; in 2013, the Gas EE Standards target total therm savings of 1.8% of 2012 retail therm sales. Targeted savings increase annually in subsequent years until they reach a cumulative annual reduction in retail therm sales of 6% by 2020. UNS Gas' programs, during 2011 and 2012, saved cumulative energy equal to approximately 0.35% of its 2011 retail therm sales.

New and existing DSM programs, renewable energy technology that displaces gas, and certain energy efficient building codes are acceptable means to meet the Gas EE Standards. The Gas EE Standards provide for the recovery of costs incurred to implement DSM programs. UNS Gas' DSM programs and rates charged to retail customers for these programs are subject to ACC approval.

Retail Electric Competition Rules

In 1999, the ACC approved the Rules which provided a framework for the introduction of retail electric competition in Arizona. Certain portions of the ACC Rules that enabled ESPs to compete in the retail market were invalidated by an Arizona Court of Appeals decision in 2004. In 2008, the ACC opened an administrative proceeding to address the Rules, and in 2012, a small number of companies filed applications for a Certificate of Convenience and Necessity ("CC&N") with the ACC to provide competitive retail electric services in TEP's service territory as an ESP.

In May 2013, the ACC voted to commence a process to consider the possibility of opening Arizona to retail electric competition. The first step in the process was to solicit comments on questions raised by the ACC on the potential benefits and risks to Arizona electric customers associated with retail electric competition. In July 2013, various parties, including TEP and UNS Electric, filed comments. TEP and UNS Electric oppose opening Arizona to retail electric competition. Responsive comments from the parties were filed in August 2013. In September 2013, the ACC voted to close the proceeding on retail competition, citing legal and constitutional challenges to which retail competition would be subject. The ACC decision to end its exploration into the deregulation of Arizona's electricity market signals improved coordination between the ACC, State utilities and industrial and commercial customers, and supports the improved views and ratings of Arizona's regulatory environment. UNS Energy cannot predict if the ACC will consider retail electric competition in the future. See "Risk Factors — Risk Factors Relating to the Post-Acquisition Business and Operations of the Corporation and UNS Energy".

Rates

TEP

In June 2013 the ACC issued the 2013 TEP rate order (the "2013 TEP Rate Order") that resolved the rate case filed by TEP in July 2012. The 2013 TEP Rate Order approved new rates for TEP effective July 1, 2013. The 2013 TEP Rate Order approved a non-fuel base rate increase of US$76 million over adjusted 2011 revenues, with an Original Cost Rate Base ("OCRB") of approximately US$1.5 billion and a Fair Value Rate Base ("FVRB") of approximately US$2.3 billion. In addition, the 2013 TEP Rate Order included a Lost Fixed Cost Recovery ("LFCR") mechanism to enable TEP to recover lost non-fuel costs due to lost kWh sales attributed to energy efficiency programs and distributed generation and an Environmental Compliance Adjustor ("ECA") mechanism that allows TEP to recover costs of complying with environmental standards required by federal or other governmental agencies between rate cases. The 2013 TEP Rate Order also approved adjustments and modifications to TEP's Purchased Power and Fuel Adjustment Clause mechanism, which permits TEP to pass through most fuel costs, including final reclamation costs, to customers.

The 2013 TEP Rate Order approved a 10.0% return on equity, a long-term cost of debt of 5.18% and a short-term cost of debt of 1.42%, resulting in a weighted average cost of capital of 7.26%. TEP's capital structure is permitted to be 43.5% equity, 56.0% long-term debt and 0.5% short-term debt. The provisions of the 2013 TEP Rate Order also give consideration to the fair value of TEP's rate base by approving a 0.68% return on the incremental difference of approximately US$800 million between TEP's OCRB and its FVRB.

UNS Gas

In April 2012, the ACC approved a base rate increase of US$2.7 million with an OCRB of US$183 million, as well as a LFCR mechanism to enable UNS Gas to recover lost fixed cost revenues as a result of implementing the Gas EE Standards. The LFCR mechanism is expected to recover lost fixed cost revenues of less than US$0.1 million in 2013, based on estimated lost retail therm sales from May through December 2012. The rate order approved by the ACC is based on an ROE of 9.75%, a common equity of 50.8% and long-term debt of 49.2%. The new rates became effective on May 1, 2012.

In October 2013, the ACC approved an increase to the existing Purchased Gas Adjustor ("PGA") credit from 4.5 cents per therm to 10 cents per therm in order to reduce the US$17 million over-collected PGA balance as of September 30, 2013. The new PGA credit will be effective for the period of November 1, 2013 through April 30, 2014.

UNS Electric

In December 2012, UNS Electric filed a general rate case with the ACC which was settled with ACC staff in September 2013. The settlement agreement provides for a non-fuel retail base rate increase of approximately US$3 million on an OCRB of approximately US$213 million and an FVRB of approximately US$283 million. The terms of the settlement agreement provide UNS Electric with a return on equity of 9.50% and a long-term cost of debt of 5.97% resulting in a weighted average cost of capital of 7.83%, with a capital structure of 52.6% equity and 47.4% long-term debt. In addition, the terms of the settlement agreement provide for (i) an LFCR mechanism to recover certain non-fuel costs relating to kWh sales lost due to energy efficiency programs and distributed generation and (ii) a transmission cost adjustor, which allows for more timely recovery of transmission costs associated with serving retail customers. The settlement agreement was approved by the ACC on December 17, 2013 and new rates will become effective on January 1, 2014.

Environmental Regulation

UNS Energy and its operations are subject to environmental regulation by federal, state and local bodies. The generating facilities of TEP and UNS Electric are primarily regulated by the EPA. Applicable environmental rules and regulations in the United States have changed significantly in the last five years and are expected to continue to evolve in ways that may limit, impair or add expense to the operations of UNS Energy and its regulated utility subsidiaries.

Clean Air Act Requirements

The EPA limits the amount of sulfur dioxide ("SO_2"), nitrogen oxide ("NO_X"), particulate matter, mercury and other emissions released into the atmosphere by power plants in the United States. As a result, TEP was required to spend US$2 million in 2012, US$8 million in 2011 and US$18 million in 2010 in construction costs to perform upgrades on its generating facilities to comply with environmental requirements, including costs associated with TEP's share of new pollution control equipment installed at San Juan.

TEP will continue to incur costs relating to environmental compliance and may incur added costs to comply with future changes in federal and state environmental laws, regulations and permit requirements at its power plants. Complying with these changes may reduce operating efficiency. TEP expects to recover the cost of environmental compliance from its retail customers. TEP currently has sufficient emission allowances to comply with acid rain SO_2 regulations.

The Clean Air Act requires the EPA to develop emission limit standards for hazardous air pollutants that reflect the maximum achievable control technology. In February 2012, the EPA issued final rules called the Mercury and Air Toxics Standards ("MATS") setting limits for mercury emissions and other hazardous air pollutants from power plants. The Navajo, Four Corners and Springerville power generation stations are currently expected to be affected by MATS, with TEP's portion of total capital expenditures required to bring the plants into compliance with MATS currently expected to be approximately US$50 million. TEP's portion of total required annual operating costs for the required equipment upgrades at Navajo, Four Corners and Springerville is currently expected to be less than US$6 million.

Climate Change

In 2007, the Supreme Court ruled in Commonwealth of *Massachusetts, et al. v. EPA* that carbon dioxide and other Greenhouse Gases ("GHG") are air pollutants under the Clean Air Act. In 2009, the EPA issued a final endangerment finding stating that GHGs endanger public health and welfare. The EPA issued final GHG regulations for new motor vehicles in 2010 triggering GHG permitting requirements for power plants under the Clean Air Act. As of January 2011, air quality permits for new sources, including power plants, and modifications of existing sources such as power plants must include an analysis for GHG controls. In the near term, based on current construction plans, UNS Energy does not currently expect the new permitting requirements to impact TEP or UNS Electric. In March 2012, the EPA released its proposed new source performance standard for GHGs. TEP does not currently anticipate this standard will have any material impact on its existing facilities.

In June 2013, U.S. President Barack Obama directed the EPA to move forward with carbon emission regulations for both new and existing fossil-fueled power plants. In September 2013, the EPA issued a re-proposed rule for new power plants. UNS Energy does not anticipate that a final rule related to new fossil-fueled power plant sources will have a significant impact on operations. For existing power plants, the President ordered the EPA to propose carbon emission standards by June 1, 2014, to finalize those standards by June 1, 2015 and to require states to submit their implementation plans to meet the standards by June 30, 2016. UNS Energy is working with federal and state regulatory agencies to promote compliance flexibility in the rules impacting existing fossil-fuel fired power plants. UNS Energy cannot predict the ultimate outcome of these matters.

Regional Haze Rules

The EPA's regional haze rules require emission controls known as Best Available Retrofit Technology ("BART") for certain industrial facilities emitting air pollutants that reduce visibility. The BART rules call for all states to establish goals and emission reduction strategies for improving visibility in national parks and wilderness areas. States must submit these goals and strategies to the EPA for approval. Because Navajo and Four Corners are located on the Navajo Indian Reservation, they are not subject to state oversight. The EPA directly oversees Regional Haze planning for these power plants.

Complying with the EPA's BART findings, and with other future environmental rules, may make it economically impractical to continue operating the Navajo, San Juan and Four Corners power plants or for individual owners to continue to participate in these power plants. TEP cannot predict the ultimate outcome of these matters. See "Risk Factors — Risk Factors Relating to the Post-Acquisition Business and Operations of the Corporation and UNS Energy".

Navajo

In January 2013, the EPA proposed an alternative BART determination for the Navajo generating facility that would require the installation of Selective Catalytic Reduction ("SCR") technology on all three units at Navajo by 2023. In July 2013, SRP, along with other stakeholders including impacted government agencies, environmental organizations and tribal representatives submitted an agreement to the EPA that would achieve greater NO_X emission reductions than the EPA's proposed BART rule. In September 2013, EPA issued a supplemental proposal incorporating the provisions of the agreement as a better-than-BART alternative.

Among other things, the agreement calls for the shutdown of one unit at Navajo or an equivalent reduction in emissions by 2020. The shutdown of one unit will not impact the total amount of energy delivered to TEP from Navajo. Additionally, the remaining Navajo participants would be required to install SCR or an equivalent technology on the remaining two units by 2030. As part of the agreement, the current owners have committed to cease their operation of conventional coal-fired generation at Navajo no later than December 2044. The Navajo Nation can continue operation after 2044 at its election.

If SCR technology is ultimately required at Navajo, TEP estimates its share of the capital cost relating to the required modifications will be approximately US$42 million. Also, the installation of SCR technology at Navajo could increase the power plant's particulate emissions which may require that baghouses be installed. TEP estimates that its share of the capital expenditure for baghouse installation would be approximately US$43 million. TEP's share of annual operating costs relating to the modifications is estimated at less than US$1 million for each of the control technologies (SCR and baghouses).

San Juan

In August 2011, the EPA issued a Federal Implementation Plan ("FIP") establishing new emission limits for air pollutants at San Juan. These requirements are more stringent than those proposed by the State of New Mexico. The FIP requires the installation of SCR technology with sorbent injection on all four units within five years to reduce NO_X and control sulfuric acid emissions by September 2016. TEP estimates its share of the cost to install SCR technology with sorbent injection at San Juan to be between US$180 million and US$200 million. TEP expects its share of the annual operating costs for SCR technology to be approximately US$6 million.

In 2011, PNM filed a petition for review of and a motion to stay the FIP with the Tenth Circuit United States Court of Appeals ("Circuit Court"). In addition, PNM filed a request for reconsideration of the rule with the EPA and a request to stay the effectiveness of the rule pending the EPA's reconsideration and the review by the Circuit Court. The State of New Mexico filed similar motions with the Circuit Court and the EPA. Several environmental groups were granted permission to join in opposition to PNM's petition to review in the Circuit Court. In addition, WildEarth Guardians filed a separate appeal against the EPA challenging the FIP's five-year implementation schedule. PNM was granted permission to join in opposition to that appeal. In March 2012, the Circuit Court denied PNM's and the State of New Mexico's motion for stay. Oral argument on the appeal was heard in October 2012 and the parties are currently awaiting the Circuit Court's decision.

In February 2013, the State of New Mexico, the EPA and PNM signed a non-binding agreement that outlines an alternative to the FIP. The terms of the agreement include: the retirement of San Juan Units 2 and 3 by December 31, 2017; the replacement by PNM of those units with non-coal generation sources; and the installation of Selective Non-Catalytic Reduction technology ("SNCR") on San Juan Units 1 and 4 by January 2016 or later depending on the timing of EPA approvals. The New Mexico Environmental Department prepared a revision to the regional haze State Implementation Plan ("SIP") incorporating the provisions of the agreement, and in September 2013, the New Mexico Environmental Improvement Board approved the SIP revision. The SIP revision now awaits final EPA approval.

TEP estimates its share of the cost to install SNCR technology on San Juan Unit 1 would be approximately US$35 million. TEP's share of incremental annual operating costs for SNCR is estimated at $1 million. TEP owns 340 MW or 50% of San Juan Units 1 and 2. At September 30, 2013, the book value of TEP's share of San Juan Unit 2 was US$114 million. If Unit 2 is retired early, TEP expects to request ACC approval to recover, over a reasonable time period, all costs associated with the early closure of the unit. TEP is evaluating various sources to replace the generation capacity that would be lost if Unit 2 is retired early. Any decision regarding early closure and replacement resources will require various actions by third parties as well as UNS Energy board and regulatory approvals. UNS Energy cannot predict the ultimate outcome of this matter. See "Risk Factors — Risk Factors Relating to the Post-Acquisition Business and Operations of the Corporation and UNS Energy".

If the State of New Mexico's proposed plan is not accepted by the EPA, TEP may begin making capital expenditures to install SCRs on San Juan Units 1 and 2 to meet the FIP compliance deadline.

Four Corners

In August 2012, the EPA finalized the Regional Haze FIP for Four Corners. The final FIP requires SCR technology to be installed on all five units by 2017. However, the FIP also includes an alternative plan that allows APS to close their wholly owned Units 1, 2 and 3 and install SCR technology on Units 4 and 5. This option allows the installation of SCR technology to be delayed until July 2018. In either case, TEP's estimated share of the capital costs to install SCR technology at Four Corners is approximately US$35 million. TEP's share of annual operating costs for SCR at Four Corners is estimated at US$2 million.

Springerville

Regional haze regulations requiring emission control upgrades do not apply to Springerville currently and are not likely to impact Springerville operations until after 2018.

Sundt

In July 2013, the EPA determined that Sundt Unit 4 is subject to BART requirements. The EPA postponed its expected release of a proposed BART requirement for Sundt Unit 4 until December 2013, with a final determination expected in May 2014. While TEP does not agree that Sundt Unit 4 is BART eligible, in anticipation of EPA's proposed BART requirements, TEP has submitted a plan for EPA approval proposing to eliminate coal as a fuel after December 2017.

Coal Combustion Residuals

In 2010, the EPA proposed a rule to regulate the handling and disposal of coal ash and other Coal Combustion Residuals ("CCRs"). The EPA has proposed regulating CCRs as either non-hazardous solid waste or hazardous waste. The hazardous waste alternative would require additional capital investments and operational costs for both storage and handling at plants and transportation to disposal locations. Both the hazardous waste and non-hazardous solid waste alternatives would require liners for new ash landfills or expansions to existing ash landfills. The rules will apply to

CCRs produced by all of TEP's coal-fired generating assets. San Juan may also be subject to separate regulations being drafted by the Office of Surface Mining Reclamation and Enforcement because it disposes of CCRs in surface mine pits.

The EPA has not yet indicated a preference for an alternative. Each option would allow CCRs to be beneficially reused or recycled as components of other products. TEP currently expects the EPA to issue a final rule relating to the disposal of CCRs in 2014.

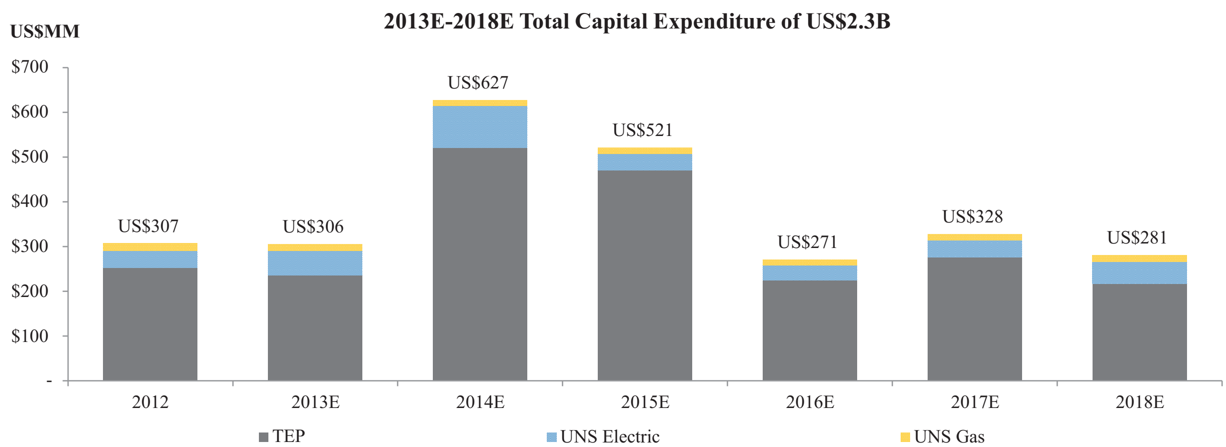
TEP also is contractually obligated to pay a portion of the environmental reclamation costs incurred at generating stations in which it has a minority interest and is obligated to pay similar costs at the coal mines that supply these generating stations. While TEP has recorded the portion of its obligations for such reclamation costs that can be determined at this time, the total costs for final reclamation at these sites are unknown and could be substantial. Costs associated with mine reclamation are flowed through to TEP's retail customers as incurred.

UNS Gas and UNS Electric

UNS Gas and UNS Electric are each subject to environmental regulation of air and water quality, resource extraction, waste disposal and land use by federal, state and local authorities. The facilities and operations of UNS Gas and UNS Electric are in substantial compliance with existing regulations.

Capital Expenditures

Capital expenditures for the UNS Energy utility subsidiaries over the period from 2013 through 2018 are projected to total approximately US$2.3 billion. The estimated capital expenditures include the capital required to finance the anticipated acquisition of Gila River in 2014 and the capital required to exercise the Springerville Unit 1 lease purchase options in December 2014 and January 2015. See "The Acquired Businesses — TEP — Generating and Other Resources" and "The Acquired Business — TEP — Future Generating Resources".



Strong operating cash flows are expected to provide flexibility in the financing of capital expenditure projects. The majority of UNS Energy's capital investments are expected to be funded largely through internally generated operating cash flow and long-term debt issued by the UNS Utilities.

The rate base of UNS Energy is expected to grow by a CAGR of approximately 7% through 2018 as a result of capital expenditures related to UNS Energy's generation diversification, including increased generation from renewable resources, and meeting mandated emission reductions applicable to the regulated utility subsidiaries. See "The Acquired Business — Environmental Regulation".

Operating and Maintenance Expense

Base O&M expenses, including the cost of generating plant maintenance, represent the fundamental level of expenses related to maintaining UNS Energy's core business. UNS Energy management has maintained a focus on the control of base O&M. As a result, base O&M has remained flat at approximately US$270 million annually for 2009 through 2012. Base O&M expenses are estimated to be in the range of US$280 to US$290 million annually for 2013 through 2015, which equates to an average annual growth rate of 1.2% since 2009.

Outstanding Indebtedness

For information on the financial condition and results of UNS Energy, reference is made to the audited consolidated financial statements of UNS Energy as of December 31, 2012 and 2011, including the consolidated statements of income and cash flows for each of the years ended December 31, 2012, 2011 and 2010, and the unaudited consolidated financial statements of UNS Energy for the three and nine months ended September 30, 2013, each of which is included in this Prospectus.

Long-Term Debt and Capital Lease Obligations

UNS Energy's long-term debt and capital lease obligations as of September 30, 2013 are described in the chart below. Fortis expects all such debt will remain in place following the Acquisition:

Long-Term Debt	Maturity	Interest Rate	As of September 30, 2013 (millions of U.S. dollars)
UNS Energy:			
Credit Agreement [1]	2016	Variable	52
TEP:			
Variable Rate Tax-Exempt Bonds [2]	2014-2016	Variable	215
Unsecured Fixed Rate Bonds	2020-2040	4.50%-6.38%	609
Unsecured Notes	2021-2023	3.85%-5.15%	400
UNS Gas and UNS Electric:			
Senior Unsecured Notes	2015-2026	5.39%-7.10%	200
UNS Electric:			
Unsecured Term Loan	2015	Variable	30
Total Long-Term Debt			1,506
Capital Lease Obligations [3]			299
Total Long-Term Debt and Capital Lease Obligations			1,805

(1) UNS Energy reflects borrowings under its revolving credit facility as long-term debt, as it has the ability and intention to leave the balance of its borrowings outstanding for at least the next twelve months.

(2) TEP also holds in treasury an aggregate of US$150 million of bonds issued by the Industrial Development Authority of the County of Apache which it may reissue or refund in the future. Subsequent to September 30, 2013, TEP acquired an additional US$100 million of bonds issued by the Industrial Development Authority of the County of Apache, which bonds are subject to a mandatory tender for purchase in 2018 and mature in 2032. TEP will use the proceeds of such bonds to redeem an existing series of outstanding bonds in the amount of US$100 million.

(3) Includes the long-term and current capital lease obligations with respect to TEP's leased interests in Springerville Unit 1, the Springerville Coal Handling Facilities and the Springerville Common Facilities. In August 2013, TEP recorded an increase of US$39 million due to TEP's commitment to purchase lease interests in January 2015.

Credit Facilities

UNS Energy maintains a US$125 million stand-alone revolving credit facility (the "UNS Energy Credit Facility"), expiring in November 2016, to provide committed liquidity beyond its cash balance. The facility is secured by a pledge of the common stock of Millennium, UniSource Energy Services and UniSource Energy Development Company. At September 30, 2013, UNS had approximately US$73 million available under its revolver and US$3 million in cash and cash equivalents.

TEP currently maintains a US$200 million revolving credit facility (the "TEP Credit Facility"), which expires in November 2016. As of September 30, 2013, TEP had US$1 million in borrowings under its revolver and US$35 million in cash and cash equivalents. TEP's credit agreements also provide for a US$186 million letter of credit facility, which also expires in November 2016 and a US$37 million letter of credit facility that expires in 2014 (together, the "TEP LOC Facilities"). The TEP LOC Facilities are used to support TEP's tax-exempt variable rate bonds.

UNS Gas and UNS Electric share a US$100 million revolving credit facility (the "UNS Electric/UNS Gas Credit Facility") that also expires in November 2016. Each utility's maximum draw under the facility is US$70 million but the total combined borrowed amount cannot exceed US$100 million and each utility is only liable for its own borrowings. As at September 30, 2013, UNS Gas had no borrowings under the revolver and US$27 million in cash and cash equivalents, while UNS Electric had US$23 million drawn on the revolver and US$4 million in cash and cash equivalents.

In August 2011, UNS Electric entered into a four-year $30 million variable rate term loan credit agreement (the "UNS Electric Term Loan"). The interest rate currently in effect under this facility is three-month London Interbank Offer Rate ("LIBOR") plus 1.125%. At the same time, UNS Electric entered into a fixed-for-floating interest rate swap in which UNS Electric will pay a fixed rate of 0.97% and receive a three-month LIBOR rate on a US$30 million notional amount over a four-year period ending August 2015. The UNS Electric Term Loan is guaranteed by UNS Electric's immediate shareholder UniSource Energy Services.

The UNS Energy Credit Facility, TEP Credit Facility, UNS Electric/UNS Gas Credit Facility and UNS Electric Term Loan contain restrictive covenants including restrictions on liens, mergers and sales of assets. These agreements also require that a certain maximum leverage ratio not be exceeded. Concurrently with the issuance of 2013 Series A Industrial Development Revenue Bonds on November 1, 2013, TEP entered into a covenants agreement with the purchaser of such bonds, STI Institutional & Government Inc., which contains covenants and events of default that are the same, in all material respects, as those in the TEP Credit Facilities and include restrictions on mergers and sales of assets, in addition to mandating that TEP not exceed a maximum leverage ratio. At September 30, 2013, UNS Energy and its subsidiaries were in compliance in all material respects with the terms of their respective credit agreements, the TEP LOC Facilities and the UNS Electric Term Loan.

THE ACQUISITION AGREEMENT

Set forth below is a description of the material terms of the Acquisition Agreement. The description is a summary only and is qualified in its entirety by the full text of the Acquisition Agreement. A copy of the Acquisition Agreement has been filed on the Corporation's SEDAR profile at www.sedar.com. This summary is not intended to be, and should not be relied upon as, disclosure of any facts and circumstances relating to Fortis or UNS Energy.

Purchase Price

Pursuant to the terms of the Acquisition Agreement, Fortis and certain subsidiaries of Fortis (collectively, the "Purchaser") have agreed to acquire UNS Energy for an aggregate purchase price of approximately US$4.3 billion, comprised of approximately US$2.5 billion in cash (the "Cash Purchase Price") for all of the issued and outstanding shares of UNS Energy and the assumption of approximately US$1.8 billion of debt on closing of the Acquisition.

Representations and Warranties

Under the Acquisition Agreement, the Purchaser and UNS Energy have made various representations and warranties. UNS Energy's representations and warranties relate to, among other things: organization and qualification of UNS Energy and its subsidiaries; capitalization; authority to enter into the Acquisition Agreement and to effect the Acquisition; no conflict; required filings, consents and approvals; possession of permits and compliance with all applicable laws; securities regulatory filings; reports and financial statements; sufficiency of internal control and disclosure controls; absence of undisclosed liabilities; absence of certain material changes or events since December 31, 2012; accuracy and completeness of information to be included in the UNS Energy proxy statement; pension and employee benefits; labour and employment matters; disclosure of material contracts; existence and status of litigation; real and personal property; environmental matters; intellectual property; tax matters; fairness opinion of financial advisor; adequacy of insurance; required shareholder vote; broker engagement and involvement; regulation as a utility; regulatory filings; non-applicability of takeover laws; disclosure of forward contracts and derivatives trading; regulatory proceedings and absence of dissenter's rights. The representations and warranties of the subsidiaries of the Corporation that are party to the Acquisition Agreement relate to, among other things: organization and qualification of such subsidiaries; authority to enter into the Acquisition Agreement and to effect the Acquisition; no conflict; required filings, consents and approvals; accuracy and completeness of information supplied to UNS Energy for inclusion in its proxy statement; existence and status of litigation; no ownership of UNS Energy capital stock by the Corporation or any of its subsidiaries; availability of funds to consummate the Acquisition; ownership of the merger subsidiary and prior activities of such subsidiary; absence of management agreement; and brokerage fees.

Covenants

UNS Energy and the Purchaser have made covenants relating to the closing of the Acquisition and related matters. UNS Energy and the Purchaser have agreed, among other things, to use their reasonable best efforts to take all appropriate action and to do all things necessary to complete and otherwise give effect to the Acquisition, including to satisfy the conditions described below under "— Closing Conditions" and to obtain the regulatory consents and approvals described below under "— Closing Conditions — Governmental Consents and Approvals", including to make all necessary filings with the relevant government authorities; provided that Purchaser shall not be required to, and UNS Energy shall not, take any action other than actions as are expressly agreed by the Purchaser and UNS Energy, that individually or in the aggregate would reasonably be expected to have a material adverse effect on UNS Energy or Fortis, in each case following the Acquisition. In addition, UNS Energy and the Purchaser have agreed not to take any action (including through their respective affiliates), including acquiring or making any investment in any corporation, partnership, limited liability company or other business organization or any division or assets thereof, that would reasonably be expected to cause a material delay in the satisfaction of the closing conditions contained in the Acquisition Agreement or the consummation of the Acquisition. The Purchaser has also covenanted in the Acquisition Agreement to indemnify all past and present directors, officers and employees of UNS Energy and its subsidiaries for a period of six years following closing of the Acquisition to the same extent as such persons are indemnified on the date of the Acquisition Agreement and to maintain certain employee benefits at pre-Acquisition levels for a period of two years following closing of the Acquisition.

During the period from the date of the Acquisition Agreement until the closing of the Acquisition, UNS Energy will, and UNS Energy will cause its subsidiaries to: (i) conduct their operations only in the ordinary course of business; (ii) comply in all material respects with applicable laws, orders and permits; and (iii) use their commercially reasonable best efforts (A) to maintain satisfactory relationships with third parties and governmental entities and (B) to preserve their business organization, key officers and employees, except as permitted or required by the Acquisition Agreement, or as required by law, government authority or the NYSE.

The Acquisition Agreement also contains specific restrictive covenants with respect to certain non-permissible activities of UNS Energy and its subsidiaries during the period from the date of the Acquisition Agreement until the closing of the Acquisition. These restrictive covenants provide that, subject to certain exceptions (including as permitted or required by the Acquisition Agreement), UNS Energy and its subsidiaries will respectively not take certain actions without the prior written approval of the Purchaser (such approval not to be unreasonably withheld, delayed or conditioned), including the following: (i) amend its articles, by-laws or equivalent organizational documents; (ii) issue equity securities other than pursuant to existing security-based compensation arrangements; (iii) sell, pledge, transfer or dispose of material assets; (iv) declare or pay dividends or make other distributions (other than the payment of regular quarterly cash dividends at the times and in the manner paid in the past and in an amount per share of UNS Energy common stock of not more than US$0.435 to holders of UNS Energy common stock on or before December 31, 2013 and US$0.48 after such date, inter-company dividends between the UNS Energy companies and dividend equivalent rights under security-based compensation arrangements and a stub period dividend to holders of record at the effective time of the Acquisition, if applicable); (v) acquire, redeem or amend the terms of its equity securities; (vi) merge or consolidate with another entity, or liquidate, dissolve, restructure, recapitalize or otherwise reorganize (or adopt any plan or resolution related thereto); (vii) acquire (including by exercising any right to acquire) or obtain any right to acquire (including by merger, consolidation or acquisition of stock or assets) any interest in any entity or any assets, other than acquisitions of inventory in the ordinary course of business, acquisition set out in the capital expenditure plan disclosed to the Purchaser or any assets the consideration for which does not exceed a specified threshold; (viii) incur any indebtedness except in connection with refinancings of existing indebtedness as such indebtedness matures upon market terms and conditions, draw-downs of existing credit facilities, or for borrowings in accordance with the financing plan of UNS Energy disclosed to the Purchaser; (ix) make loans, advances or capital contributions to, or investments in, any person (other than a wholly owned subsidiary) in excess of a specified threshold; (x) increase the compensation payable to directors, officers or employees other than otherwise required by law or in the ordinary course of business consistent with past practice or establish or amend any employee compensation plan or collective bargaining agreement other than in the ordinary course of business; (xi) make or revise a material tax election that is inconsistent with past practices; (xii) make any material change in accounting policies or procedures other than as required by US GAAP; (xiii) make or commit to capital expenditures in excess of the capital expenditures budget, other than as required by a governmental entity or as a result of an emergency; (xiv) terminate or allow a material permit to lapse; (xv) enter into, amend or terminate early a material contract or enter into any transaction with an affiliate or waive, release, assign, pay, discharge, settle or satisfy any material claims, liabilities or obligations other than in the ordinary course of business consistent with past practice or as otherwise required by their terms; (xvi) terminate employees or introduce a program or effort concerning the termination of employment of employees (other than employee terminations in the ordinary course); (xvii) hire any officer-level employee other than to replace any officer (not including UNS Energy's chief executive officer, chief financial officer or chief operating officer) that voluntarily terminates his or her employment or whose employment is terminated for cause, or terminate any officer-level employee, other than for cause; (xviii) settle or agree to settle any litigation, investigation, proceeding or other claim in excess of specified threshold amounts; (xix) redeem, repurchase, defease, cancel or otherwise acquire any indebtedness except pursuant to inter-company transactions or as otherwise permitted by the Acquisition Agreement; (xx) change energy price risk management policies or marketing of energy or enter into physical commodity transactions, futures options and derivatives not permitted by existing UNS Energy policy; (xxi) make any material change to the terms of insurance policies; (xxii) lower pricing for energy or capacity sold wholesale other than in the ordinary course; (xxiii) assign or license any material intellectual property; or (xxiv) authorize or enter into any contract to do any of the foregoing. In addition, from the date of the Acquisition Agreement until the time of closing, UNS Energy and its subsidiaries must obtain the Purchaser's consent prior to initiating any general rate case and must consult with the Purchaser prior to making any material change to its rates or charges.

Closing Conditions

The Acquisition Agreement provides that the obligation of the Purchaser or UNS Energy to consummate the Acquisition is subject to the fulfillment of a number of conditions, each of which may be waived by joint action of the contracting parties, including the following:

(i) Shareholder Approval. UNS Energy must have obtained approval of the Acquisition Agreement and the transactions contemplated thereby, including the Acquisition, from the holders of UNS Energy's common shares representing a majority of the votes of all outstanding common shares entitled to vote at a duly convened meeting of UNS Energy's common shareholders ("UNS Energy Shareholder Approval").

(ii) Accuracy of Representations and Warranties. The representations and warranties made by UNS Energy (other than as described below), without regard to materiality or Company Material Adverse Effect qualifiers, must be true and correct as of the date of the Acquisition Agreement and as of the closing date of the Acquisition, except where the failure of such representations and warranties to be true and correct, individually or in the aggregate, have not had and would not be reasonably likely to have a Company Material Adverse Effect. The representations and warranties made by UNS Energy with respect to its capitalization must be true and correct in all respects (except for *de minimis* inaccuracies) as of the date of the Acquisition Agreement and as of the closing date of the Acquisition. The representations and warranties made by UNS Energy with respect to authority to enter into and perform its obligations under the Acquisition Agreement and absence of conflict with organizational documents, without regard to materiality or Company Material Adverse Effect qualifiers, must be true and correct in all material respects as of the date of the Acquisition Agreement and as of the closing date of the Acquisition. The representations and warranties made by the Purchaser (other than those with respect to authority), without regard to materiality qualifiers, must be true and correct as of the date of the Acquisition Agreement and as of the closing date of the Acquisition, except where the failure of such representations and warranties to be true and correct, individually or in the aggregate, would not reasonably be expected to prevent or materially delay or materially impair the ability of the Purchaser to consummate the Acquisition. The representations and warranties made by the Purchaser with respect to authority to enter into and perform its obligations under the Acquisition Agreement must be true and correct in all respects as of the Acquisition Agreement and as of the closing date of the Acquisition.

"Company Material Adverse Effect" is defined in the Acquisition Agreement to mean any fact, change, event, circumstance, occurrence, effect or development that is materially adverse to: (i) the business, assets, liabilities, financial condition or results of operations of UNS Energy or its subsidiaries, taken as a whole; or (ii) the ability of UNS Energy to consummate the Acquisition or to perform its obligations under the Acquisition Agreement on a timely basis in accordance with the Acquisition Agreement, provided that certain external events will not constitute a Company Material Adverse Effect unless they specifically relate to or have a materially disproportionate effect on UNS Energy and its subsidiaries, taken as a whole, compared with other entities operating in the natural gas and electric utility industry.

(iii) Material Adverse Effect. There must not have occurred any Company Material Adverse Effect or any change, event, occurrence, effect or development that, individually or in the aggregate, has had or would reasonably be expected to result in a Company Material Adverse Effect.

(iv) Performance of Covenants. The other party has performed or complied in all material respects with all agreements and covenants required by the Acquisition Agreement to be performed or complied with on or prior to the closing date of the Acquisition.

(v) Legal Proceedings. There must not be any order, decree, judgment, injunction or other ruling or law that has the effect of making the merger of an indirect wholly owned subsidiary of Fortis into UNS Energy illegal or would otherwise prohibit consummation of the Acquisition.

(vi) Governmental Consents and Approvals. Each party has received the governmental and regulatory consents and approvals required to be obtained by it under the Acquisition Agreement. The regulatory approvals that must be obtained prior to the closing of the Acquisition include:

(a) the issuance by the ACC of an order approving the Acquisition under Arizona Administrative Code R14-2-801 et seq., which shall not contain any term which has the effect of reducing the consideration received by holders of UNS Energy common stock;

(b) the approval of the Acquisition by FERC;

(c) pre-approvals of license transfers with the Federal Communications Commission;

(d) the expiration or termination of any applicable waiting period, together with any extensions thereof, under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended; and

(e) written confirmation from the Committee on Foreign Investment in the United States ("CFIUS") that CFIUS has reviewed the information provided to it regarding the Acquisition and based on its review and, where applicable, investigation, has determined that there are no unresolved national security concerns with respect to the Acquisition.

Superior Proposal

Pursuant to the terms of the Acquisition Agreement, UNS Energy and its subsidiaries, officers, directors, employees and representatives are not permitted to, directly or indirectly, encourage or facilitate another acquisition proposal, or any inquiry or proposal by another person that could reasonably be expected to lead to another acquisition proposal. However, if at any time prior to receipt of UNS Energy Shareholder Approval, UNS Energy receives a bona fide written acquisition proposal from a third party that its board of directors determines in good faith constitutes or is reasonably likely to lead to an acquisition proposal more favourable to UNS Energy than the terms of the Acquisition (a "Superior Proposal"), UNS Energy may (i) furnish information with respect to UNS Energy to the third party making the acquisition proposal and/ or (ii) participate in discussions or negotiations with such third party; provided that the third party enters into an acceptable confidentiality agreement and UNS Energy provides to the Purchaser any information made available to the third party which was not previously provided or made available to the Purchaser. Under the terms of the Acquisition Agreement, UNS Energy is obligated to keep the Purchaser informed, in all material respects, on a reasonably prompt basis of the status and details of any acquisition proposal, and to provide to the Purchaser as soon as reasonably practicable copies of all written material specifying the material terms and conditions of such acquisition proposal.

UNS Energy's board of directors may not withdraw or take any action inconsistent with its recommendation that its common shareholders approve and adopt the Acquisition (which for greater certainty includes taking a neutral position with respect to a third party acquisition proposal), unless, after receiving a Superior Proposal and before such Superior Proposal is withdrawn, UNS Energy has first provided written notice to the Purchaser specifying the reasons for UNS Energy board's change of recommendation, including the material terms and conditions of such Superior Proposal and attaching a copy of the most current draft of any written agreement relating thereto, has negotiated in good faith with the Purchaser to amend the terms of the Acquisition Agreement and has determined that UNS Energy board's failure to change its recommendation would be a breach of its fiduciary duties under applicable law and such Superior Proposal continues to be Superior Proposal taking into account any changes to the terms of the Acquisition Agreement committed to by the Purchaser.

In addition, if there occurs any change, event, occurrence, effect or development that (i) is material to UNS Energy and its subsidiaries taken as a whole, (ii) does not relate to a third party acquisition proposal and (iii) is not known to UNS Energy's board of directors as of the date of the Acquisition Agreement, then UNS Energy's board of directors may make a change to its recommendation that its common shareholders approve and adopt the Acquisition, if (and only if) UNS Energy's board of directors determines in good faith that the failure to do so would be a breach of its fiduciary duties under applicable law; provided, however, that UNS Energy's board of directors has provided prior written notice to the Purchaser specifying the reasons therefor, has negotiated in good faith with the Purchaser to amend the terms of the Acquisition Agreement and taking into account any changes to the terms of the Acquisition Agreement committed to by the Purchaser, UNS Energy's board of directors has determined in good faith that its failure to make a change of recommendation would be a breach of its fiduciary duties under applicable law.

Termination

The Acquisition Agreement may be terminated by the Purchaser or UNS Energy at any time prior to closing in certain circumstances, whether before or after receipt of the UNS Energy Shareholder Approval, including:

(i) the mutual written consent of the Purchaser and UNS Energy;

(ii) if the Acquisition has not closed by December 11, 2014 provided, however, that if the only unsatisfied conditions to closing is obtaining the required regulatory approvals, then such date shall automatically be extended without any further action to June 11, 2015 (subject to any waiting period imposed by law);

(iii) the UNS Energy Shareholder Approval is not obtained upon a vote by holders of UNS Energy's outstanding common shares entitled to vote at a duly convened meeting of UNS Energy's shareholders;

(iv) if a court of competent jurisdiction or a government authority issues a final order or injunction permanently enjoining, restraining or prohibiting the Acquisition;

(v) prior to receipt of UNS Energy Shareholder Approval, by (a) UNS Energy upon receipt of an acquisition proposal which is determined, by the board of directors of UNS Energy, to be a Superior Proposal, provided that, among other things, UNS Energy has subsequently negotiated in good faith with the Purchaser to amend the terms of the Acquisition Agreement; or (b) Purchaser in the event that (I) the board of directors of UNS Energy changes its prior recommendation that its common shareholders approve and adopt the Acquisition or (II) UNS Energy enters into a definitive agreement with respect to a Superior Proposal; or

(vi) if the other party fails to comply with any of its covenants and agreements or breaches its representations and warranties, and such failure to comply is not cured within 30 days of receiving written notice of such breach and results in a failure to satisfy the conditions to closing.

In the event that the Acquisition Agreement is terminated by the Purchaser or UNS Energy pursuant to paragraph (v), UNS Energy will be required to pay to the Purchaser a termination fee of US$63,900,000 (the "Termination Fee").

In the event that the Acquisition Agreement is terminated: (a) by the Purchaser or UNS Energy pursuant to paragraphs (ii) or (iii) or by the Purchaser pursuant to paragraph (vi); (b) prior to the termination pursuant to paragraph (ii), the UNS Energy shareholder meeting or a breach or failure giving rise to the Purchaser's right to terminate pursuant to paragraph (vi), as applicable, where an acquisition proposal by a third party has been made to UNS Energy or its board of directors or publicly disclosed and not withdrawn prior to the termination; and (c) UNS Energy enters into a definitive agreement with respect to, or consummates, an acquisition proposal by a third party within 12 months after such termination, UNS Energy will be required to pay to the Purchaser the Termination Fee less any fees and expenses previously paid to the Purchaser on termination.

UNS Energy will be required to reimburse the Purchaser for all fees and expenses incurred or paid for in connection with the Acquisition, including fees and expenses in connection with the Purchaser's equity and debt financing, not in excess of US$12,500,000 in the aggregate where the Acquisition Agreement is terminated: (a) by the

Purchaser or UNS Energy pursuant to paragraphs (ii) or (iii) or by the Purchaser pursuant to paragraph (vi); and (b) prior to the termination pursuant to paragraph (ii), the UNS Energy shareholder meeting or a breach or failure giving rise to the Purchaser's right to terminate pursuant to paragraph (vi), as applicable, where an acquisition proposal by a third party has been made to UNS Energy or its board of directors or publicly disclosed and not withdrawn prior to the termination.

FINANCING THE ACQUISITION

The Acquisition will be financed with the proceeds of the Acquisition Credit Facilities. The amount outstanding under the Acquisition Credit Facilities following the closing of the Acquisition will be reduced with the net proceeds of the final instalment under the Offering and the Concurrent Private Placement. See "Use of Proceeds".

Acquisition Credit Facilities

For purposes of financing the Acquisition, on December 11, 2013, Fortis obtained a commitment letter from The Bank of Nova Scotia providing for an aggregate of $2.0 billion non-revolving term credit facilities in favour of Fortis consisting of a $1.7 billion Short-Term Bridge Facility, repayable in full nine months following its advance, and a $300 million Medium-Term Bridge Facility, repayable in full on the second anniversary of its advance. The Acquisition Credit Facilities, together with the $600 million the Corporation has agreed to maintain under its existing Revolving Facility to cover one-third of the principal amount of the Debentures in the event of a mandatory redemption (as described under "Details of the Offering — Debentures Redemption"), would be sufficient, if necessary, to fund the full cash portion of the purchase price for the Acquisition.

As at December 19, 2013, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.7 billion (not including the Acquisition Credit Facilities), of which $2.2 billion was unused, including an unused amount of approximately $820 million under the Corporation's $1 billion committed Revolving Facility. Fortis (on a consolidated basis) intends to use the net proceeds of the first instalment under the Offering and the Concurrent Private Placement which are expected to be $563,400,000 in the aggregate (assuming no exercise of the Over-Allotment Option) to repay borrowings under the Revolving Facility and for other general corporate purposes, including financing equity requirements of the Corporation's subsidiaries. Fortis (on a consolidated basis) intends to use the net proceeds of the final instalment under the Offering and the Concurrent Private Placement which are expected to be $1,164,600,000 in the aggregate (assuming no exercise of the Over-Allotment Option) to repay borrowings under the Acquisition Credit Facilities following the closing of the Acquisition and for other Acquisition-Related Expenses. See "Use of Proceeds".

Fortis is required to make prepayments of the Acquisition Credit Facilities in an amount equal to the net cash proceeds from any common or preferred equity or bond or other debt offerings by Fortis. Net proceeds from any equity offering will be applied firstly to repay the Short-Term Bridge Facility and secondly to repay the Medium-Term Bridge Facility. Net proceeds from any bond or other debt offerings, including the aggregate amount of the final instalment payable under this Offering and the Concurrent Private Placement, will be applied firstly to repay the Medium-Term Bridge Facility and secondly to repay the Short-Term Bridge Facility. Fortis expects that the remainder of borrowings under the Acquisition Credit Facilities will be reduced or repaid from the proceeds of one or more offerings of Common Shares, long-term debt securities, first preference shares or second preference shares or from amounts extended under other debt financings in order to restore the current consolidated capitalization structure of Fortis following the Acquisition.

The credit agreement pursuant to which the Acquisition Credit Facilities will be extended (the "Acquisition Credit Agreement") will contain certain prepayment options in favour of Fortis and certain prepayment obligations upon the occurrence of certain events. In particular, the net proceeds of any equity or debt offering by Fortis (other than certain permitted equity or debt offerings for strategic investments) will be required to be used to prepay the Short-Term Bridge Facility and Medium-Term Bridge Facility, respectively, and any prepayment under the Acquisition Credit Facilities may not be re-borrowed.

The Acquisition Credit Agreement will contain customary representations and warranties and affirmative and negative covenants of Fortis that will closely resemble those in the Revolving Facility. As part of these covenants, Fortis will be required to maintain a consolidated debt to consolidated capitalization ratio of not more than 0.70:1, which is consistent with the Revolving Facility.

Customary fees are payable by Fortis in respect of the Acquisition Credit Facilities and amounts outstanding under the Acquisition Credit Facilities will bear interest at market rates.

Concurrent Private Placement

The Corporation and the Selling Debentureholder have entered into subscription agreements dated December 11, 2013 (each a "Subscription Agreement") pursuant to which Private Placement Subscribers will purchase on an instalment and private placement basis, Private Placement Debentures at a price of $1,000 per Private Placement Debenture for aggregate gross proceeds to the Selling Debentureholder of $206,000,000 (the "Concurrent Private Placement"). The closing of the Concurrent Private Placement is scheduled to occur on the Closing Date, which is expected to take place on or about January 9, 2014 or such other date as may be agreed upon by the Corporation, the Selling Debentureholder and the Underwriters, but not later than January 20, 2014 and is conditional on the concurrent closing of the Offering. Each Private Placement Subscriber will be paid a commitment fee in cash equal to $20.00 per $1,000 aggregate principal amount of Private Placement Debentures subscribed for by such Private Placement Subscriber payable on the Closing Date. The Private Placement Debentures, the Instalment Receipts representing such Private Placement Debentures and the Common Shares issuable on the conversion of the Private Placement Debentures will be subject to resale restrictions for a four-month period from the closing of the Private Placement, in accordance with applicable Canadian securities laws. Fortis has applied to list the Instalment Receipts (representing the Private Placement Debentures) and the Common Shares issuable on the conversion of the Private Placement Debentures on the TSX.

Fortis, the Selling Debentureholder and Scotia Capital, RBC, TDSI and CIBC have entered into an agency agreement dated December 11, 2013 (the "Agency Agreement") pursuant to which Scotia Capital, RBC, TDSI and CIBC are, collectively, entitled to receive an agency fee of $20.00 per $1,000 aggregate principal amount of Private Placement Debentures in connection with the Concurrent Private Placement. Such agency fee will be paid on the Final Instalment Date, provided that the final instalment has been paid in respect of such Private Placement Debentures.

Purchasers of Debentures under this Prospectus should not rely on the fact that the Private Placement Subscribers have decided to participate in the Concurrent Private Placement and make an investment in the Private Placement Debentures. The net proceeds of the first instalment under the Concurrent Private Placement will be used to repay amounts outstanding under the Revolving Facility. The net proceeds of the final instalment under the Concurrent Private Placement will be used to reduce the amount outstanding under the Acquisition Credit Facilities following the closing of the Acquisition. See "Use of Proceeds". The subscription price for the Private Placement Debentures was negotiated between the Corporation, the Selling Debentureholder and each of the Private Placement Subscribers.

CAPITALIZATION

Upon completion of the Offering, the closing of the Acquisition and assuming the payment of the final instalment and the conversion of the Debentures and the Private Placement Debentures into Common Shares, there will be an aggregate of 58.6 million additional Common Shares outstanding, or 66.4 million additional Common Shares if the Over-Allotment Option is exercised in full (in each case on a non-fully diluted basis).

The following table sets out the consolidated capitalization of the Corporation as at September 30, 2013 and on a *pro forma* basis, assuming no exercise of the Over-Allotment Option, as of such date after giving effect to (i) the net proceeds of the Offering, determined after deducting the Underwriters' fee and estimated expenses of the Offering on an after-tax basis, (ii) the net proceeds of the Concurrent Private Placement, determined after deducting the commitment fee, the agency fee and estimated expenses of the Concurrent Private Placement, (iii) the Acquisition Credit Facilities to be drawn at the closing of the Acquisition to fund the balance of the purchase price, (iv) the Acquisition and the assumption of the UNS Energy debt, (v) the conversion of the Debentures and the Private Placement Debentures into Common Shares and (vi) the changes in Common Shares, long-term debt, capital lease and finance obligations from October 1, 2013 up to and including December 19, 2013. See "Changes in Share and Loan Capital Structure" and "Financing the Acquisition". The financial information set out below has been prepared in accordance with US GAAP. See "Index to Financial Statements".

	As at September 30, 2013 (unaudited)	*Pro forma* As at September 30, 2013 (unaudited)(1)
	(in millions of dollars)	
Total debt, capital lease and finance obligations (2) (net of cash)	7,503	10,315
Shareholders' equity		
Securities offered hereby (3)	—	1,749
Common Shares (4)	3,760	3,782
Preference shares	1,229	1,229
Additional paid-in capital	16	16
Accumulated other comprehensive loss	(101)	(101)
Retained earnings	1,013	989
Total capitalization (5)	13,420	17,979

(1) After giving effect to (i) the net proceeds of the Offering, assuming no exercise of the Over-Allotment Option, determined after deducting the Underwriters' fee and estimated expenses of the Offering on an after-tax basis, (ii) the net proceeds of the Concurrent Private Placement, determined after deducting the commitment fee, the agency fee and estimated expenses of the Concurrent Private Placement, (iii) the Acquisition Credit Facilities to be drawn at the closing of the Acquisition to fund the balance of the purchase price, (iv) the Acquisition and the assumption of the UNS Energy debt and (v) the changes in Common Shares, long-term debt, capital lease and finance obligations from October 1, 2013 up to and including December 19, 2013. See "Changes in Share and Loan Capital Structure".

(2) Includes long-term debt, capital lease and finance obligations, including the current portion and short-term borrowings.

(3) Assuming the conversion of the Debentures and the Private Placement Debentures into Common Shares.

(4) Does not include the Common Shares issuable upon the conversion of the Debentures and the Private Placement Debentures, which are included as "Securities offered hereby".

(5) Excludes non-controlling interests.

EARNINGS COVERAGE RATIOS

The Corporation's interest requirements on all of its outstanding debt securities after giving effect to the issue of $1.8 billion principal amount of 4.00% Debentures distributed hereunder and under the Concurrent Private Placement (and the repayment of outstanding amounts under the Revolving Facility using the payment of the first instalment) amounted to $459 million and $471 million for the 12 months ended December 31, 2012 and the 12 months ended September 30, 2013, respectively. The Corporation's dividend requirements on all of its First Preference Shares for the 12 months ended December 31, 2012 and 12 months ended September 30, 2013, adjusted to a before-tax equivalent, amounted to $55 million using an effective income tax rate of 14.1% and $60 million using an effective income tax rate of 5.0%, respectively. The Corporation's earnings before interest and income tax for the 12 months ended December 31, 2012 and

12 months ended September 30, 2013 were $782 million and $761 million, respectively, which is 1.52 times and 1.43 times, respectively, the Corporation's aggregate interest and dividend requirements for the periods.

The earnings coverage ratios of the Corporation, calculated on a *pro forma* basis after giving effect to the Acquisition, including the conversion of the Debentures and the Private Placement Debentures into Common Shares and the Acquisition Credit Facilities remaining outstanding after the payment of the final instalment, are calculated as follows: (i) the Corporation's interest requirements on all of its outstanding debt securities amounted to $547 million and $416 million for each of the 12 months ended December 31, 2012 and the 9 months ended September 30, 2013, respectively; (ii) the Corporation's dividend requirements on all of its First Preference Shares for the 12 months ended December 31, 2012 and 9 months ended September 30, 2013, adjusted to a before-tax equivalent, amounted to $57 million using an effective income tax rate of 17.2% and $48 million using an effective income tax rate of 8.7%, respectively; and (iii) the Corporation's earnings before interest and income tax for the 12 months ended December 31, 2012 and 9 months ended September 30, 2013 were $1,033 million and $799 million, respectively, which is 1.71 times and 1.72 times, respectively, the Corporation's aggregate interest and dividend requirements for the periods.

SHARE CAPITAL OF FORTIS

The authorized share capital of the Corporation consists of an unlimited number of Common Shares, an unlimited number of First Preference Shares issuable in series and an unlimited number of Second Preference Shares issuable in series, in each case without nominal or par value. As at December 19, 2013, 213,145,372 Common Shares, 7,993,500 Cumulative Redeemable First Preference Shares, Series E (the "First Preference Shares, Series E"), 5,000,000 Cumulative Redeemable First Preference Shares, Series F (the "First Preference Shares, Series F"), 9,200,000 Cumulative Redeemable Five-Year Fixed Rate Reset First Preference Shares, Series G (the "First Preference Shares, Series G"), 10,000,000 Cumulative Redeemable Five-Year Fixed Rate Reset First Preference Shares, Series H (the "First Preference Shares, Series H"), 8,000,000 Cumulative Redeemable First Preference Shares, Series J (the "First Preference Shares, Series J") and 10,000,000 Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series K (the "First Preference Shares, Series K") were issued and outstanding. The Corporation's 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 J and First Preference Shares, Series K are listed on the TSX under the symbols "FTS", "FTS.PR.E", "FTS.PR.F", "FTS.PR.G", "FTS.PR.H", "FTS.PR.J" and "FTS.PR.K", respectively.

CHANGES IN SHARE AND LOAN CAPITAL STRUCTURE

The following describes the changes in the share and loan capital structure of Fortis since September 30, 2013:

(i) During the period from October 1, 2013 up to and including December 19, 2013, Fortis issued an aggregate of 727,112 Common Shares pursuant to the Corporation's DRIP, CSPP and ESPP and upon the exercise of options granted pursuant to the 2006 and 2002 Stock Option Plans, for aggregate consideration of approximately $22 million.

(ii) During the period from October 1, 2013 up to and including December 19, 2013, the Corporation's consolidated long-term debt, capital lease and finance obligations, including current portions and committed credit facility borrowings classified as long-term debt, increased by approximately $81 million, principally due to the following:

  (a) the issuance by the Corporation of US$285,000,000 3.84% senior unsecured notes, series C due October 1, 2023 and US$40,000,000 5.08% senior unsecured notes, series D due October 1, 2043, the proceeds of which were used to repay committed credit facility borrowings;

  (b) the issuance by Newfoundland Power of 30-year $70,000,000 4.805% first mortgage bonds, the proceeds of which were partially used to repay credit facility borrowings; and

  (c) credit facility borrowings at FortisAlberta to fund capital expenditures and for general corporate purposes.

(iii) As a result of the Offering and the Concurrent Private Placement, after giving effect to the assumed conversion of the Debentures and the Private Placement Debentures into Common Shares, shareholders' equity in the Corporation will increase by approximately $1.7 billion.

PRIOR SALES

The following table summarizes the issuances by the Corporation of Common Shares and securities convertible into Common Shares within the 12 months prior to the date of this Prospectus:

Date	Security	Weighted Average Issue Price or Exercise Price per Security, as applicable	Number of Securities
December 1, 2012	Common — DRIP (1)	$32.42	493,631
December 1, 2012	Common — ESPP (2)	$33.06	70,016
December 1, 2012	Common — CSPP (3)	$33.06	12,404
December 2013	Common — Exercise of Stock Options (4)	$27.12	161,261
January 2013	Common — Exercise of Stock Options (4)	$25.08	113,179
February 2013	Common — Exercise of Stock Options (4)	$14.61	73,086
March 1, 2013	Common — DRIP (1)	$32.94	562,571
March 1, 2013	Common — ESPP (2)	$33.58	146,325
March 1, 2013	Common — CSPP (3)	$33.58	8,777
March 20, 2013	Issue of Stock Options	$33.58	807,600
March 2013	Common — Exercise of Stock Options (4)	$12.81	5,660
April 2013	Common — Exercise of Stock Options (4)	$17.94	135,132
May 2013	Common — Exercise of Stock Options (4)	$18.59	43,990
June 1, 2013	Common — DRIP (1)	$32.93	483,209
June 1, 2013	Common — ESPP (2)	$33.50	70,835
June 1, 2013	Common — CSPP (3)	$33.58	7,960
June 27, 2013	Common (5)	$32.50	18,500,000
August 2013	Common — Exercise of Stock Options (4)	$19.45	16,400
September 1, 2013	Common — DRIP (1)	$29.58	591,651
September 1, 2013	Common — ESPP (2)	$30.17	75,470
September 1, 2013	Common — CSPP (3)	$30.17	9,928
September 2013	Common — Exercise of Stock Options (4)	$22.29	7,740
October 2013	Common — Exercise of Stock Options (4)	$22.29	10,000
November 2013	Common — Exercise of Stock Options (4)	$28.19	4,000
December 1, 2013	Common — DRIP (1)	$30.75	625,911
December 1, 2013	Common — ESPP (2)	$31.33	76,068
December 1, 2013	Common — CSPP (3)	$31.35	9,133
December 13, 2013	Common — Exercise of Stock Options (4)	$18.41	2,000

(1) Issued pursuant to the Corporation's Dividend Reinvestment Plan ("DRIP").

(2) Issued pursuant to the Corporation's Employee Share Purchase Plan ("ESPP").

(3) Issued pursuant to the Corporation's Consumer Share Purchase Plan ("CSPP").

(4) Issued on the exercise of options granted pursuant to the Executive, 2002 and 2006 Stock Option Plans of the Corporation.

(5) Issued on the exchange of 18,5000,000 subscription receipts issued by the Corporation on June 27, 2012 in connection with the acquisition of CH Energy Group.

TRADING PRICES AND VOLUMES

The following tables set forth, for the periods indicated, the reported high and low daily trading prices and the aggregate volume of trading of the Corporation's 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 J; and First Preference Shares, Series K, on the TSX.

	Trading of Common Shares		
	TSX		
	High	Low	Volume
	($)	($)	(#)
2012			
December	34.35	32.83	9,203,571
2013			
January	34.85	33.92	7,028,930
February	34.89	32.89	8,565,427
March	34.29	33.21	9,213,786
April	35.08	33.06	9,634,522
May	35.14	33.00	11,446,339
June	33.32	30.70	13,237,638
July	32.95	31.25	8,084,459
August	32.45	29.92	8,815,840
September	31.57	29.78	13,894,725
October	32.80	30.76	9,216,065
November	32.84	31.00	9,949,813
December 1 to 19	31.68	29.51	8,448,469

	Trading of First Preference Shares, Series E			Trading of First Preference Shares, Series F		
	TSX			TSX		
	High	Low	Volume	High	Low	Volume
	($)	($)	(#)	($)	($)	(#)
2012						
December	27.33	26.80	25,304	25.96	25.74	46,410
2013						
January	27.19	26.64	38,132	26.05	25.80	63,277
February	27.03	26.30	61,519	26.25	25.74	372,278
March	26.64	26.18	161,461	26.02	25.79	68,561
April	26.83	26.27	62,483	26.17	25.65	49,615
May	26.54	25.40	151,923	26.06	25.08	133,510
June	26.27	25.95	17,127	25.12	22.89	109,880
July	26.16	25.90	25,989	24.76	23.28	93,996
August	26.15	25.15	102,324	23.64	21.51	160,433
September	26.04	25.80	277,950	24.12	21.67	268,832
October	26.16	25.90	142,029	24.77	22.87	112,290
November	26.22	25.83	110,659	24.05	23.25	83,563
December 1 to 19	26.25	25.62	140,540	23.51	21.66	206,519

	Trading of First Preference Shares, Series G			Trading of First Preference Shares, Series H		
	TSX			TSX		
	High	Low	Volume	High	Low	Volume
	($)	($)	(#)	($)	($)	(#)
2012						
December	24.74	24.05	382,796	25.75	25.40	132,976
2013						
January	25.10	24.32	619,282	26.03	25.43	236,790
February	25.31	24.87	462,897	26.25	25.45	232,420
March	25.38	24.99	231,399	26.38	25.80	293,989
April	25.39	25.09	166,680	26.26	25.29	166,015
May	25.78	25.01	233,188	25.92	25.10	142,715
June	25.12	22.33	141,639	25.46	24.05	169,198
July	24.92	24.03	172,482	24.62	22.53	186,298
August	24.05	22.90	152,750	22.98	19.90	266,107
September	23.82	23.20	186,736	22.17	20.68	254,009
October	24.10	23.35	210,044	22.30	20.12	330,407
November	24.19	23.78	166,399	22.38	20.80	447,312
December 1 to 19	24.08	23.76	221,999	21.55	21.00	552,597

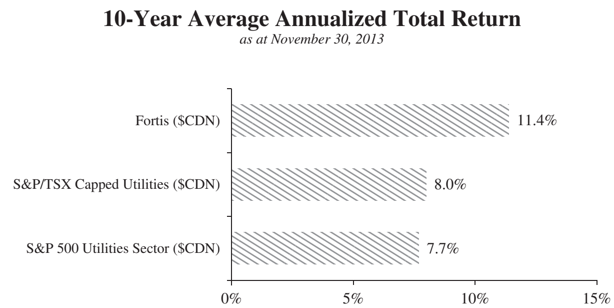
	Trading of First Preference Shares, Series J			Trading of First Preference Shares, Series K		
	TSX			TSX		
	High	Low	Volume	High	Low	Volume
	($)	($)	(#)	($)	($)	(#)
2012						
December	25.80	25.23	247,752	—	—	—
2013						
January	26.09	25.54	455,909	—	—	—
February	26.27	25.56	296,524	—	—	—
March	26.12	25.60	307,650	—	—	—
April	26.26	25.85	271,529	—	—	—
May	26.10	25.52	166,192	—	—	—
June	25.60	22.31	206,705	—	—	—
July (1)	24.49	22.75	193,041	25.29	24.90	619,484
August	23.58	20.99	239,500	25.25	24.25	216,119
September	23.75	21.13	378,127	24.84	24.10	158,746
October	23.75	22.33	215,901	24.76	24.20	329,716
November	23.59	22.37	252,735	24.78	23.96	137,442
December 1 to 19	22.70	21.24	318,874	24.84	24.05	160,077

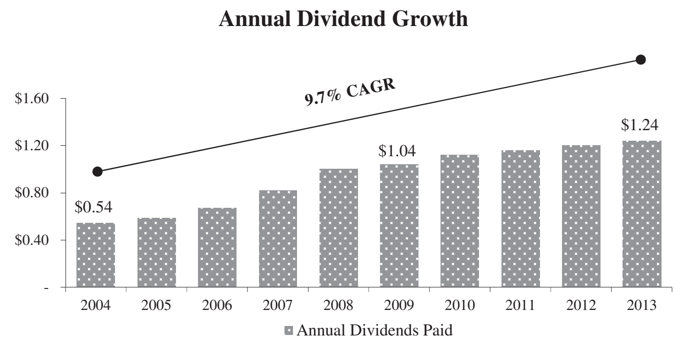
(1) The First Preference Shares, Series K commenced trading on July 18, 2013.

DIVIDEND POLICY

Dividends on the Common Shares are declared at the discretion of the board of directors of Fortis (the "Board of Directors"). The Corporation declared cash dividends on its Common Shares of $1.21 in 2012 and $1.17 in 2011. On September 23, 2013, the Board of Directors declared a fourth quarter dividend of $0.31 per Common Share, which was paid on December 1, 2013 to holders of record on November 15, 2013, resulting in Fortis paying cumulative cash dividends on its Common Shares of $1.24 in 2013. On December 9, 2013, the Board of Directors declared a first quarter dividend of $0.32 per Common Share, payable on March 1, 2014 to holders of record on February 14, 2014. Fortis has increased its annual Common Share dividend payment for 41 consecutive years.

Earnings and dividend growth at Fortis have resulted in annualized total shareholder returns of 11.4% over the past 10 years. Over the same period, Fortis has maintained average annual dividend growth of 9.7%.





Regular quarterly dividends at the prescribed annual rate have been paid on all of the First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series J; and First Preference Shares, Series K, respectively. The Board of Directors declared a fourth quarter dividend on the First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series J; and First Preference Shares, Series K, on September 23, 2013, in each case in accordance with the applicable prescribed annual rate, which was paid on December 1, 2013 to holders of record on November 15, 2013. On December 9, 2013, the Board of Directors declared a first quarter dividend on the First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series J; and First Preference Shares, Series K, in each case in accordance with the applicable prescribed annual rate, payable on March 1, 2014 to holders of record on February 14, 2014.

DESCRIPTION OF COMMON SHARES

Dividends

Dividends on Common Shares are declared at the discretion of the Board of Directors. Holders of Common Shares are entitled to dividends on a *pro rata* basis if, as and when declared by the Board of Directors. Subject to the rights of the holders of the First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive dividends in priority to or rateably with the holders of the Common Shares, the Board of Directors may declare dividends on the Common Shares to the exclusion of any other class of shares of the Corporation.

Liquidation, Dissolution or Winding-Up

On the liquidation, dissolution or winding-up of Fortis, holders of Common Shares are entitled to participate rateably in any distribution of the 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 rateably with the holders of the Common Shares.

Voting Rights

Holders of the Common Shares are entitled to receive notice of and to attend all annual and special meetings of the shareholders of Fortis, other than separate meetings of holders of any other class or series of shares, and to one vote in respect of each Common Share held at such meetings.

DETAILS OF THE OFFERING

The Offering consists of $1,594,000,000 aggregate principal amount of Debentures represented by Instalment Receipts at a price of $1,000 per Debenture, which are being sold by the Selling Debentureholder on an instalment basis. The first instalment of $333 per $1,000 principal amount of Debentures is payable on the Closing Date. The final instalment of $667 per $1,000 principal amount of Debentures is payable following notification to holders (the "Final Instalment Notice") that (i) the Corporation has received all regulatory and governmental approvals required to finalize the Acquisition and (ii) the Corporation and UNS Energy have fulfilled or waived all other outstanding conditions precedent to closing the Acquisition, other than those which by their nature cannot be satisfied until the closing of the Acquisition (collectively, the "Approval Conditions") as itemized in the Acquisition Agreement. Such notification, which must be given by no later than June 30, 2015, will establish a date for payment of the final instalment (the "Final Instalment Date"), which shall not be less than 15 days nor more than 90 days following the date of such notice. Payment of the final instalment in full must be received by the Custodian by no later than 3:30 p.m. (Toronto time) on the Final Instalment Date. Holders should make arrangements with the securities broker, trust company or other financial institution through which they hold Instalment Receipts to pay the final instalment sufficiently in advance of the Final Instalment Date to ensure that such payment is received by the Custodian prior to this deadline.

The Selling Debentureholder

The Selling Debentureholder is a wholly owned subsidiary of Fortis organized under the *Companies Act* (Nova Scotia) on December 19, 2008 and continued under the *Canada Business Corporations Act* on March 6, 2013. The Selling Debentureholder will acquire the Debentures offered pursuant to this Prospectus from Fortis for the purpose of participating in this Offering. The Selling Debentureholder will also be the seller of the Private Placement Debentures. See "Financing the Acquisition — Concurrent Private Placement".

If the Over-Allotment Option is exercised by the Underwriters, the Selling Debentureholder will acquire the Debentures purchased in the Over-Allotment Option from Fortis and will sell them to the Underwriters on the terms and conditions set out in the Underwriting Agreement.

Instalment Receipts

The following is a summary of the material attributes and characteristics of the Instalment Receipts representing Debentures and the rights and obligations of holders thereof. This summary does not purport to be complete and is subject to, and is qualified in its entirety by, the terms of the instalment receipt and pledge agreement (the "Instalment Receipt Agreement"), to be dated as of the Closing Date, among the Corporation, the Selling Debentureholder, the Underwriters and Computershare Trust Company of Canada in its capacity as custodian and security agent (the "Custodian"). Copies of the Instalment Receipt Agreement will be available for inspection at the principal offices of the Custodian in Toronto and Montreal. A prospective purchaser of Debentures represented by Instalment Receipts should carefully review the Instalment Receipt Agreement, a copy of which will also be available on the Corporation's SEDAR profile at www.sedar.com.

Holders of Instalment Receipts will be bound by the terms of the Instalment Receipt Agreement. The Instalment Receipt Agreement will provide that legal title to the Debentures offered hereby will be held by the Custodian following payment of the first instalment and until the Final Instalment Date provided the final instalment has been fully paid to the Custodian on behalf of the Selling Debentureholder on or before the Final Instalment Date (and in no case later than 3:30 p.m. (Toronto time) on the Final Instalment Date). The Debentures offered hereby will be pledged to the Selling Debentureholder by the Underwriters at Closing and the physical certificates representing the Debentures will be held in the possession of the Custodian, as security agent, on behalf of the Selling Debentureholder, subject to the terms of the Instalment Receipt Agreement.

Prior to payment of the final instalment, beneficial ownership of Debentures will be represented by Instalment Receipts. An Instalment Receipt will evidence, among other things, the fact that the first instalment has been paid in respect of the Debenture represented thereby and the right of a holder thereof, subject to compliance with the provisions of the Instalment Receipt Agreement, (i) to have the pledge of the Debentures released following the Final Instalment Date provided that payment in full of the final instalment with respect to such Debentures has been received by the Custodian on or prior to such date or (ii) if the Debentures are redeemed by the Corporation prior to payment of the final instalment, to receive (after the Custodian pays the final instalment to the Selling Debentureholder on behalf of the holder) $333 per underlying Debenture plus accrued and unpaid interest on such Debenture up to but excluding the redemption date. A holder of an Instalment Receipt is deemed to have assumed the obligation to pay the final instalment on or before the Final Instalment Date and to have acquired beneficial ownership of the Debenture represented by the Instalment Receipt, subject to the pledge of such Debenture which secures such obligation. A holder of an Instalment Receipt is further deemed to agree that the foregoing pledge will remain in effect and be binding and effective notwithstanding any transfer of or other dealings with the Instalment Receipt and the rights evidenced or arising thereby.

The Corporation shall as soon as practicable following satisfaction of the Approval Conditions (but no later than June 30, 2015) cause a Final Instalment Notice to be given to holders of Debentures represented by Instalment Receipts (i) confirming that all Approval Conditions have been fulfilled to the satisfaction of the Corporation, (ii) setting the Final Instalment Date (which shall not be less than 15 days nor more than 90 days following the date that such notice is first given) and (iii) advising holders of their ability to exercise the conversion privilege with respect to Debentures represented by their Instalment Receipts concurrently with the payment of the final instalment. See "—Debentures — Conversion Rights". The Selling Debentureholder shall also cause to be issued a press release containing particulars of the Final Instalment Notice. Payment of the final instalment is required regardless of whether a holder receives the Final Instalment Notice, directly or indirectly.

A holder of an Instalment Receipt will be entitled to make payment, in accordance with the provisions of the Instalment Receipt Agreement, of the final instalment at any time following receipt of the Final Instalment Notice and prior to 3:30 p.m. (Toronto time) on the Final Instalment Date. **A holder of Instalment Receipts that fails to pay the final instalment in full by 3:30 p.m. (Toronto time) on the Final Instalment Date (a "Defaulting Holder") has no further right to pay the final instalment and all rights and privileges of the Defaulting Holder described below under "— Rights and Privileges" shall immediately cease (unless otherwise waived by the Selling Debentureholder).**

Subject to compliance with the provisions of the Instalment Receipt Agreement and timely payment of the final instalment, the Custodian will, as soon as practicable on or after the Final Instalment Date, discharge and release the pledge of the Debentures represented by such Instalment Receipts and such Debentures (or the Common Shares into which the Debentures may be converted) will be held through the facilities of CDS Clearing and Depository Services Inc. ("CDS"), in which case the holder will receive only a customer confirmation of purchase of the Debentures (or, if the conversion privilege is exercised, the underlying Common Shares) from the holder's CDS Participant (as defined below).

The Instalment Receipts representing the Debentures are issued in "book-entry only" form and must be purchased or transferred through a participant in CDS (a "CDS Participant"). The Corporation will cause a global certificate or certificates representing any newly issued Instalment Receipts to be delivered to, and registered in the name of, CDS or its nominee. All rights and obligations of holders of Instalment Receipts must be exercised or performed through, and all notices, payments or other property to which such holders are entitled or obligated will be made or delivered by the holder holding such Instalment Receipts through CDS or the CDS Participants in accordance with the rules and procedures applicable to CDS and such CDS Participants. Each person who acquires Instalment Receipts will receive only a customer confirmation of purchase from the CDS Participant from or through which the Instalment Receipts representing the Debentures are acquired in accordance with the practices and procedures of that registered dealer. The practices of CDS Participants may vary, but generally customer confirmations are issued promptly after execution of a customer order. CDS is responsible for establishing and maintaining book-entry accounts for its CDS Participants having interests in Instalment Receipts. See "— Book-Entry Only System". **Because payment of the final instalment will be made by holders of Instalment Receipts through CDS and CDS Participants, it is strongly advised that holders make arrangements with the securities broker, trust company or other financial institution through which they hold Instalment Receipts to pay their final instalment sufficiently in advance of the Final Instalment**

Date to ensure that such payment is received by the Custodian by no later than 3:30 p.m. (Toronto time) on the Final Instalment Date.

Transfer of Instalment Receipts

The TSX has conditionally approved the listing of the Instalment Receipts (representing the Debentures and the Private Placement Debentures) on the TSX, subject to Fortis fulfilling all of the requirements of the TSX on or before March 11, 2014. It is anticipated that holders will be able to transfer Instalment Receipts through the facilities of the TSX until the close of trading on the trading day immediately preceding the Final Instalment Date following which, Instalment Receipts will stop trading on the TSX. Upon a transfer of an Instalment Receipt, the transferee will acquire the transferor's rights, subject to the pledge in favour of the Selling Debentureholder and become subject to the obligations of a holder of Instalment Receipts under the Instalment Receipt Agreement, including the assumption by the transferee of the obligation to pay the final instalment on or before the Final Instalment Date. No transfer of an Instalment Receipt after the Final Instalment Date will be accepted (except where an intermediary holds Instalment Receipts on behalf of a non-registered holder and such non-registered holder has failed to pay the final instalment when due, or with the express consent of the Selling Debentureholder).

Liability of Instalment Receipt Holders

Pursuant to the Instalment Receipt Agreement, the Underwriters will pledge the Debentures purchased on an instalment basis to secure payment of the final instalment. If payment of the final instalment is not duly received by the Custodian from a holder of Instalment Receipts when due, the Instalment Receipt Agreement will provide that (except as set out below) any Debenture then remaining pledged under the Instalment Receipt Agreement may, at the option of the Selling Debentureholder, subject to complying with applicable law, be forfeited to the Selling Debentureholder in full satisfaction of the obligations of such holder of Instalment Receipts secured thereby. The Instalment Receipt Agreement will further provide that the Selling Debentureholder may, alternatively, direct the Custodian to sell the Debentures in respect of which payment of the final instalment was not duly received, in accordance with the requirements of applicable law and of the Instalment Receipt Agreement, and remit to the Defaulting Holder of Instalment Receipts its *pro rata* portion of the proceeds of sale after deducting therefrom the amount of the remaining unpaid final instalment, the amount of any applicable withholding taxes and the Defaulting Holder's *pro rata* portion of the costs of sale (such costs not to exceed $25 per $1,000 principal amount of Debentures). **The Instalment Receipt Agreement will provide that, unless the Debentures are forfeited to the Selling Debentureholder in full satisfaction of the obligation of a Defaulting Holder, the foregoing shall not limit any other remedies available to the Selling Debentureholder against such Defaulting Holder of the Instalment Receipt in the event proceeds of such sale are insufficient to cover the amount of the final instalment and the costs of sale and accordingly, such holder shall in such circumstances remain liable to the Selling Debentureholder for any such deficiency.**

Rights and Privileges

Under the Instalment Receipt Agreement, holders of Instalment Receipts will have the same rights and privileges, and will be subject to the same limitations, as holders of Debentures. In particular, holders of Instalment Receipts will be entitled under arrangements through the Custodian, in the manner set forth in the Instalment Receipt Agreement, to (i) receive interest on the Debentures represented by Instalment Receipts until the Final Instalment Date, after which the interest rate payable on the Debentures will fall to an annual rate of 0% and interest will cease to accrue on the Debentures (ii) receive the Make-Whole Payment in respect of the Debentures represented thereby if the Final Instalment Date occurs prior to the first anniversary of the Closing Date and provided that a holder of Debentures represented by Instalment Receipts has paid the Final Instalment on or prior to the Final Instalment Date and (iii) exercise the votes attached to the Debentures represented by such Instalment Receipts. In the event that the Corporation issues (including on liquidation, dissolution or winding up) to the holders of Debentures, any securities, or options, rights or warrants to purchase any securities, or any securities convertible into or exchangeable for securities, or other property or assets of like nature, the Custodian will, as promptly as commercially reasonable sell such securities, options, rights, warrants, evidences of indebtedness, property or assets and remit *pro rata* to the holders of Instalment Receipts, the proceeds of sale net of the Custodian's costs of disposition, subject to withholding tax requirements.

Redemption of Debentures and Cancellation of Instalment Receipts

In the event that Debentures are redeemed prior to the payment of the final instalment and before the Final Instalment Date (if any), the Corporation shall, in respect of each Instalment Receipt outstanding on the date of such redemption, pay to the Selling Debentureholder, on behalf of the holder of an Instalment Receipt, an amount equal to the final instalment and pay the balance plus any accrued and unpaid interest to the holder. Payment of such redemption price will be made on the date that the Debentures are redeemed by the Corporation.

Modification

Apart from changes which do not materially prejudice the holders of Instalment Receipts as a group (which may be made without the consent of such holders), the Instalment Receipt Agreement may not be amended without the affirmative vote of the holders of Instalment Receipts entitled to not less than two-thirds of the principal amount of Debentures (including the Private Placement Debentures) represented by Instalment Receipts which are represented and voted at a meeting duly called for the purpose or rendered by instruments in writing signed by the holders of Instalment Receipts representing not less than two-thirds of the principal amount of the Debentures (including the Private Placement Debentures).

General

The Custodian may require holders of Instalment Receipts from time to time to furnish such information and documents as may be necessary or appropriate to comply with any fiscal or other laws or regulations relating to the Debentures or to rights and obligations represented by Instalment Receipts. The Custodian shall not be responsible for any taxes, duties, governmental charges or expenses which are or may become payable in respect of the Debentures or Instalment Receipts. In this regard, the Custodian shall be entitled to deduct or withhold from any payment or other distribution required or contemplated by the Instalment Receipt Agreement the appropriate amount of money or property, or to require holders of Instalment Receipts to make any required payments, and to withhold delivery of certificates representing the Debentures until satisfactory provision for payment is made, in respect of any non-resident Canadian withholding taxes or other taxes, duties or governmental charges or expenses required by applicable law to be withheld or paid.

Holders of Instalment Receipts will not be liable for charges and expenses of the Custodian except for any taxes, duties and other governmental charges which may be payable as described above.

Book-Entry Only System

Registration of interests in and transfers of Instalment Receipts will be made only through the book-entry only system of CDS (the “Book-Entry Only System”). Instalment Receipts must be purchased, transferred and surrendered through a CDS Participant. Upon purchase of any Instalment Receipts representing Debentures, the Corporation understands that the holder of Instalment Receipts will receive only a customer confirmation from the registered dealer which is a CDS Participant and from or through which the Instalment Receipts are purchased. References in this Prospectus to a holder of Instalment Receipts mean, unless the context otherwise requires, the owner of the beneficial interest in such Instalment Receipts.

The ability of a beneficial owner of Instalment Receipts to pledge such Instalment Receipts or otherwise take action with respect to such beneficial holder’s interest in such Instalment Receipts (other than through a CDS Participant) may be limited due to the lack of a physical certificate.

The Selling Debentureholder has the option to terminate registration of the Instalment Receipts through the Book-Entry Only System in which case certificates for the Instalment Receipts in fully registered form would be issued to holders of such Instalment Receipts.

Debentures

The following is a summary of the material attributes and characteristics of the Debentures. This summary does not purport to be complete and is subject to, and is qualified in its entirety by, the terms of the trust indenture (the “Indenture”) to be dated on or about the Closing Date between the Corporation, as issuer, and Computershare Trust

Company of Canada, as trustee (in such capacity, the "Trustee"). A prospective purchaser of Debentures represented by Instalment Receipts should carefully review the Indenture, a copy of which will be available on the Corporation's SEDAR profile at www.sedar.com on or about the Closing Date.

The Debentures and the Private Placement Debentures will be issued to the Selling Debentureholder on the Closing Date as the initial series under the Indenture and in the aggregate principal amount of $1,800,000,000. In the event that the Over-Allotment Option is exercised, Fortis will issue additional debentures of the same series under the Indenture.

The Debentures will be dated as of the Closing Date and will mature on the Maturity Date. The Debentures are issuable in denominations of $1,000 and integral multiples thereof and will bear interest at an annual rate of 4.00% per $1,000 principal amount of Debentures and will be payable quarterly in arrears in equal instalments on the first business day of March, June, September and December of each year to and including the Final Instalment Date to holders of record on the applicable record date. The first interest payment will be made on March 3, 2014 in the amount of $5.5890 per $1,000 principal amount of Debentures and will include interest payable from and including the date of issue. Subsequently, quarterly interest payments will be made in the amount of $10.00 per $1,000 principal amount of Debentures. A final interest payment will be made on the Final Instalment Date and will be equal to the unpaid interest accrued from the date of the last quarterly interest payment to and including the Final Instalment Date. On the day following the Final Instalment Date, the interest rate payable on the Debentures will fall to an annual rate of 0% and interest will cease to accrue on the Debentures. Based on a first instalment of $333 per $1,000 principal amount of Debenture, the effective annual yield to and including the Final Instalment Date is 12.00%, and the effective yield thereafter is 0%.

If the Final Instalment Date occurs on a day that is prior to the first anniversary of the Closing Date, holders of Debentures who have paid the final instalment on or before the Final Instalment Date will be entitled to receive, on the business day following the Final Instalment Date, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, the Make-Whole Payment, being an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the Closing Date had the Debentures remained outstanding and continued to accrue interest until such date. No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the Closing Date.

The Debentures will be direct obligations of Fortis and will not be secured by any mortgage, pledge, hypothec or other charge and will be subordinated to other liabilities of the Corporation as described under "— Subordination". The Indenture does not restrict the Corporation from incurring additional indebtedness for borrowed money or from mortgaging, pledging or charging its properties to secure any indebtedness.

Payment Upon Maturity

On the Maturity Date, the Corporation will repay the principal amount of any Debentures not converted into Common Shares and remaining outstanding, in cash. The Corporation may, at its option and without prior notice, satisfy the obligation to pay all or a portion of the principal amount of such Debentures on maturity by delivery of that number of freely tradable Common Shares obtained by dividing the principal amount of the Debentures with respect to which the Corporation is exercising such right by 95% of the Market Price.

Conversion Right

At the option of the holder and provided that payment of the final instalment has been made, each Debenture will be convertible into Common Shares on or at any time after the Final Instalment Date, but prior to the earlier of the date that the Corporation redeems the Debentures or the Maturity Date. The Conversion Price will be $30.72 per Common Share, being a conversion rate of 32.5521 Common Shares per $1,000 principal amount of Debentures, subject to adjustment in certain events. No adjustment will be made for cash dividends on Common Shares issuable upon conversion or for accrued and unpaid interest, which will be paid by the Corporation in cash. A holder of Debentures who does not exercise its conversion privilege concurrently with its payment of the final instalment in order to convert its Debentures to Common Shares on the Final Instalment Date will hold a Debenture that pays 0% interest and may be redeemed by the Corporation in whole or in part on any trading day following the Final Instalment Date at a price equal to its principal amount plus any unpaid interest which accrued to and including the Final Instalment Date.

Subject to the provisions thereof, the Indenture will provide for the adjustment of the Conversion Price in certain events including: (a) the distribution of Common Shares or securities convertible into Common Shares to holders of its Common Shares by way of stock dividend or otherwise other than an issue of Common Shares to holders of outstanding Common Shares who have elected to receive dividends in stock in lieu of receiving cash dividends paid in the ordinary course; (b) the subdivision or consolidation of the outstanding Common Shares; (c) the issuance of rights or warrants to all holders of Common Shares entitling them to acquire Common Shares or other securities convertible into Common Shares at less than the Conversion Price; (d) the distribution to all holders of Common Shares of any securities or assets (other than cash dividends and dividends in Common Shares); or (e) if an issuer bid or exchange offer is made by the Corporation for its Common Shares. There will be no adjustment of the Conversion Price in respect of any event described herein if, with the prior regulatory approval and the approval of the TSX, the holders of the Debentures are allowed to participate as though they had converted their Debentures prior to such transaction. The Corporation will not be required to make adjustments in the Conversion Price unless the effect of such adjustment would change the Conversion Price by at least 1%, provided that any adjustment of less than 1% will be carried forward and taken into account in connection with any subsequent adjustment.

No fractional Common Shares will be issued on any conversion but in lieu thereof, the Corporation will satisfy such fractional interest by a cash payment equal to the Conversion Price of such fractional interest, provided that the Corporation shall not be required to make any cash payment of less than $10.00.

Redemption

The Debentures may not be redeemed by the Corporation except that the Debentures will be redeemed by the Corporation at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the Approval Conditions will not be satisfied; (ii) termination of the Acquisition Agreement; and (iii) July 2, 2015 if the Final Instalment Notice has not been given on or before June 30, 2015. Upon any such redemption, the redemption proceeds will be paid by the Corporation to the Custodian on behalf of the holders. The Custodian will pay the following for each $1,000 principal amount of Debentures: (i) $333 plus accrued and unpaid interest to the holder of the Instalment Receipt; and (ii) $667 to the Selling Debentureholder on behalf of the holder of the Instalment Receipt in satisfaction of the final instalment. Under the terms of the Instalment Receipt Agreement, Fortis has agreed that until such time as the Debentures have been redeemed in accordance with the foregoing or the Final Instalment Date has occurred, the Corporation will at all times maintain availability under the Revolving Facility of not less than $600,000,000 to cover one-third of the principal amount of the Debentures in the event of a mandatory redemption.

In addition, after the Final Instalment Date, (i) any Debentures not converted to Common Shares may be redeemed by the Corporation at a price equal to their principal amount plus any unpaid interest which accrued prior to the Final Instalment Date and (ii) the Corporation will have the right to purchase Debentures in the open market or by tender or by private contract at prices not exceeding 100% of the principal amount thereof together with accrued and unpaid interest and costs of purchase.

Subordination

The Debentures will be direct unsecured obligations of Fortis. Payment of the principal of, interest on, the Make-Whole Payment, if any, and other amounts owing in respect of each Debenture will be subordinated in right of payment to all present and future liabilities of the Corporation for (i) moneys borrowed or raised by whatever means (including, without limitation, by means of commercial paper, bankers acceptances, debt instruments and any liability represented by bonds, debentures, notes or similar instruments), (ii) the deferred purchase price of assets or services or (iii) any trade debts in effect at any time and from time to time (collectively, the "Senior Indebtedness"). Payment of the principal of, interest on and other amounts owing in respect of each Debenture will rank *pari passu* with each other Debenture issued under the Indenture (including the Private Placement Debentures) regardless of their actual date or terms of issue, and with all other present and future unsecured and subordinated indebtedness of Fortis except as prescribed by law.

The Indenture does not limit the ability of the Corporation to incur additional indebtedness, including indebtedness that ranks senior to the Debentures or from mortgaging, pledging, charging, hypothecating, granting a security interest in or otherwise encumbering any or all of its properties to secure any indebtedness. The Indenture provides that the Corporation shall not make any payment, and the holders of Debentures shall not be entitled to demand, accelerate, institute proceedings for the collection of, or receive any payment or benefit (including, without limitation, by set-off, combination of accounts or realization of security or otherwise in any manner whatsoever) on account of indebtedness represented by the Debentures (i) in a manner inconsistent with the terms (as they exist on the date of issue) of the Debentures; (ii) at any time when an event of default has occurred under the Senior Indebtedness and is continuing, unless and until such Senior Indebtedness has been paid and satisfied in full or such default or event of default shall have been cured or waived in writing in accordance with the provisions of such Senior Indebtedness; or (iii) if the making of any such payment or the taking of any such action would create, including by the lapse of time or giving of notice, a default or an event of default under any Senior Indebtedness unless and until such Senior Indebtedness has been satisfied in full or the making of any such payment or taking of any such action would no longer create, including by lapse of time or giving of notice, a default or an event of default under any Senior Indebtedness.

In addition, the Trustee on behalf of the holders of Debentures may, at the request of the Corporation, enter into contractual subordination agreements with certain lenders of the Corporation with terms to the foregoing effect.

Events of Default

The Indenture will include the following events of default:

(a) failure to pay when due any principal or premium, if any, on the Debentures, when the same becomes due and payable whether on maturity, redemption, acceleration or otherwise, which default continues for a period of five business days;

(b) failure to pay any interest or Make-Whole Payment, if any, on the Debentures, which default continues for 30 days after the date when due;

(c) default in the delivery when due of all cash and any Common Shares or other consideration deliverable upon conversion of any Debentures, which default continues for 30 days;

(d) the Corporation's failure to comply with any of its other agreements under the Debentures or contained in the Indenture for a period 30 days after receipt of notice of default specifying such failure;

(e) default by the Corporation or any "material subsidiary" (as defined in the Indenture), with respect to any indebtedness (excluding amounts due to the holders of Debentures), where the aggregate principal amount of such indebtedness exceeds an amount equal to the greater of 2% of the consolidated net worth of Fortis at such time and $100,000,000, and (i) if the default is a payment default, such default continues to exist for a period exceeding 30 days; provided that if the payment obligation to which the default relates is accelerated, then the default shall constitute an event of default immediately following such acceleration, and (ii) if the default is not a payment default, then as a result of the default and the passing of any applicable cure period, the maturity of the obligation is accelerated; provided that, in each case, if the default is cured prior to acceleration of the Debentures, then the event of default shall be deemed to have been cured; and

(f) certain events of bankruptcy, insolvency or reorganization affecting the Corporation.

If an event of default shall have occurred and is continuing, either the Trustee or the holders of not less than 25% in aggregate principal amount of the Debentures then outstanding may declare the principal of the Debentures and any accrued and unpaid interest through the date of such declaration immediately due and payable. In the case of certain events of bankruptcy or insolvency, the principal amount of the Debentures together with any accrued interest through the occurrence of such event shall automatically become and be immediately due and payable.

Modification

The rights of the holders of the Debentures may be modified. For that purpose, among others, the Indenture will contain certain provisions which will make binding on all holders of Debentures resolutions passed at meetings of the holders of Debentures by votes cast thereat by holders of not less than 66⅔% of the principal amount of the Debentures, or rendered by instruments in writing signed by the holders of not less than 66⅔% of the principal amount of the Debentures then outstanding.

Certification and the Book-Entry Only System

Registration of interests in and transfers of Debentures represented by Instalment Receipts will be made only through the Book-Entry Only System. Debentures represented by Instalment Receipts must be purchased, transferred and surrendered through a CDS Participant. From the Closing Date to the Final Instalment Date, the Debentures will be issued in certificated and fully registered form in the name of Computershare Trust Company of Canada, in its capacity as security agent under the Instalment Receipt Agreement. Promptly following 3:30 p.m. (Toronto time) on the Final Instalment Date, provided due payment of the final instalment has been made in accordance with the terms of the Instalment Receipt Agreement, the Selling Debentureholder will cause the Custodian to deliver to CDS (i) a global certificate representing those Debentures not converted to Common Shares by exercise of the conversion right and (ii) Common Shares issued upon conversion of Debentures, in each case, to be registered in the name of CDS or its nominee. The Debentures will be represented by one or more global certificates. Thereafter, registration of interests in and transfers of the Debentures will be made only through the depository service of CDS and transfers of Common Shares will be effected electronically through the non-certificated inventory system administered by CDS.

Upon purchase of any Debentures through the Book-Entry Only System, the Corporation understands that the holder of Debentures will receive only a customer confirmation from the registered dealer which is a CDS Participant and from or through which the Debentures are purchased. References in this Prospectus to a holder of Debentures mean, unless the context otherwise requires, the owner of the beneficial interest in such Debentures.

The Corporation will have the option to terminate registration of the Debentures through the Book-Entry Only System in which case certificates for the Debentures in fully registered form would be issued to holders of such Debentures.

USE OF PROCEEDS

The net proceeds from the Offering will be, in the aggregate, $1,528,240,000, determined after deducting the Underwriters' fee and the estimated expenses of the Offering. In the event that the Over-Allotment Option is exercised in full, the net proceeds to be received by the Selling Debentureholder (and Fortis, on a consolidated basis) will be, in the aggregate, $1,757,776,000.

The Selling Debentureholder intends to use the net proceeds of the Offering and of the Concurrent Private Placement to make distributions in the amounts of $1,528,240,000 and $197,760,000, respectively, to the Corporation. See "Details of the Offering — The Selling Debentureholder".

Fortis (on a consolidated basis) intends to use the net proceeds of the first instalment under the Offering and the Concurrent Private Placement, which are expected to be $563,400,000 (assuming no exercise of the Over-Allotment Option or $636,238,300 if the Over-Allotment Option is exercised), in each case when paid to Fortis by the Selling Debentureholder, as follows: (i) to repay borrowings under the Revolving Facility, which borrowings have been incurred primarily in connection with the construction of the Waneta Expansion and financing of certain of the Corporation's subsidiaries; and (ii) for other general corporate purposes, including providing financing to the Corporation's regulated utility subsidiaries for capital expenditures. Fortis (on a consolidated basis) intends to use the net proceeds of the final instalment under the Offering and the Concurrent Private Placement, which are expected to be $1,164,600,000 (assuming no exercise of the Over-Allotment Option or $1,319,297,700 if the Over-Allotment Option is exercised), as follows: (a) to repay borrowings under the Acquisition Credit Facilities following the closing of the Acquisition; and (b) for other Acquisition-Related Expenses. See "Financing the Acquisition", "The Acquisition Agreement" and "Details of the Offering".

PLAN OF DISTRIBUTION

Pursuant to an underwriting agreement dated December 13, 2013 (the "Underwriting Agreement") among Fortis, the Selling Debentureholder and the Underwriters, the Selling Debentureholder has agreed to sell, and the Underwriters have agreed to purchase, as principals, on the Closing Date, all but not less than all of the Debentures offered hereby on an instalment basis at a price of $1,000 per $1,000 principal amount of Debentures (the "Offering Price"). The Offering Price is payable in cash to the Selling Debentureholder on delivery as follows: the first instalment of $333 per $1,000 principal amount of Debenture is payable on the Closing Date against delivery; and the final instalment of $667 per $1,000 principal amount of Debenture is payable on or before the Final Instalment Date. See "Details of the Offering — The Selling Debentureholder".

The obligations of the Underwriters under the Underwriting Agreement are several and not joint or joint and several and may be terminated by them on the basis of certain stated events. Under the Underwriting Agreement, the obligations of any Underwriter may be terminated in their discretion if, at or prior to the Closing Date: (a) there should occur or commence, or be announced or threatened, any inquiry, action, suit, investigation or other proceeding (whether formal or informal) other than any inquiry, action, suit, investigation or other proceeding based on alleged activities of the Underwriters, or any order is issued by any governmental authority, other than an order based on the alleged activities of the Underwriters, or any law or regulation is promulgated, changed or announced, which, in the reasonable opinion of the Underwriters (or any of them), is expected to prevent or materially restrict the trading in or the distribution of the Debentures, the Instalment Receipts representing the Debentures, the underlying Common Shares or any other securities of the Corporation or would be expected to have a material adverse effect on the market price or value of the Debentures, the Instalment Receipts representing the Debentures, the underlying Common Shares or any other securities of the Corporation; (b) there should develop, occur or come into effect or existence any event, action, state, condition or occurrence of national or international consequence, acts of hostilities or escalation thereof or other calamity or crisis or any change or development involving a prospective change in national or international political, financial or economic conditions, or any law, action, regulation or other occurrence of any nature whatsoever which, in the reasonable opinion of the Underwriters (or any of them), materially adversely affects or involves, or is expected to materially adversely affect or involve, financial markets generally or the business, affairs or operations of the Corporation; (c) there should occur any material change (financial or otherwise) in the business, affairs or operations of the Corporation or any change in any material fact (other than a change related solely to the Underwriters), or the Underwriters become aware of any undisclosed material information, which, in the reasonable opinion of the Underwriters (or any of them), could be expected to have a material adverse effect on the market price or value of the Debentures, the Instalment Receipts representing the Debentures or any other securities of the Corporation; or (d) the Acquisition Agreement is terminated prior to 8:00 a.m. (Toronto time) on the Closing Date.

The Underwriters are obligated to take up and pay for all of the Debentures represented by Instalment Receipts offered hereby (other than the Debentures represented by Instalment Receipts issuable on exercise of the Over-Allotment Option) if any of those Debentures are purchased under the Underwriting Agreement. The Debentures represented by Instalment Receipts offered hereby are to be taken up by the Underwriters, if at all, on or before a date not later than 42 days after the date of the receipt for the Prospectus.

The Selling Debentureholder has granted to the Underwriters the Over-Allotment Option, which is exercisable in whole or in part at any time until the date that is 30 days following the Closing Date and pursuant to which the Underwriters may purchase additional Debentures represented by Instalment Receipts equal to up to 15% of the aggregate principal amount of Debentures represented by Instalment Receipts sold in the Offering on the same terms as set forth above, to cover over-allotments, if any. This Prospectus qualifies the grant of the Over-Allotment Option and the issuance of Debentures represented by Instalment Receipts on the exercise of the Over-Allotment Option. A purchaser who acquires Debentures represented by Instalment Receipts forming part of the Underwriters' over-allocation position acquires those Debentures under this Prospectus, regardless of whether the over-allocation position is ultimately filled through the exercise of the Over-Allotment Option or secondary market purchases.

The Underwriting Agreement provides that the Underwriters will be paid a fee equal to 4.00% of the gross proceeds of the Offering ($40.00 per Debenture) in consideration for their services in connection with the Offering, one-half of which is payable on the Closing Date and the remaining one-half of which is payable on the Final Instalment Date. Accordingly, upon payment of the final instalment and assuming the final instalment payment is made for all outstanding Instalment Receipts, the total price to the public will be $1,594,000,000, the Underwriters' fee will be $63,760,000 and the net proceeds to the Selling Debentureholder will be approximately $1,528,240,000, after deducting the expenses of the Offering estimated at $2,000,000, which will be paid out of the general funds of Fortis. After the Underwriters have made reasonable efforts to sell all the Debentures represented by Instalment Receipts at the Offering Price, the Offering Price may be decreased and may be further changed from time to time to an amount not greater than that set out on the cover page, and the compensation realized by the Underwriters will be decreased by the amount that the aggregate price paid by purchasers for the Debentures represented by Instalment Receipts is less than the gross proceeds paid by the Underwriters to Fortis. The Offering Price and other terms of the Offering were determined by negotiation between the Corporation, the Selling Debentureholder and the Underwriters.

There is currently no market through which the Debentures represented by Instalment Receipts may be sold and purchasers may not be able to resell securities purchased under this Prospectus. This may affect the

pricing of the securities in the secondary market, the transparency and availability of trading prices, the liquidity of the securities and the extent of issuer regulation. The TSX has conditionally approved the listing of the Instalment Receipts (representing the Debentures and the Private Placement Debentures) and the Common Shares issuable on the conversion of the Debentures and Private Placement Debentures on the TSX, subject to Fortis fulfilling all of the requirements of the TSX on or before March 11, 2014. The Corporation has no current intention to list the Debentures or the Private Placement Debentures for trading on any exchange as it currently anticipates all Debentures and Private Placement Debentures will be converted to Common Shares on the Final Instalment Date.

Upon listing, the Instalment Receipts (representing the Debentures and the Private Placement Debentures) will be quoted and traded on the TSX in the same manner as other debentures listed on the TSX, with all bids and offers for and trades of Instalment Receipts reflecting only the partly paid capital portion of the Debentures and not accrued interest. Accrued interest will be reflected in the settlement amount and in the confirmations generated by the CDS participant from or through whom the trade was executed. Bid, offer and trading prices for the Instalment Receipts listed on the TSX will be expressed as a percentage of the $1,000 principal amount of a fully paid Debenture (and not as a percentage of the $333 first instalment already paid). In accordance with TSX trading rules, the Instalment Receipts will be quoted based on $100 principal amounts and all trades in Instalment Receipts will be made in multiples of $1,000. A board lot of Instalment Receipts is represented by one Instalment Receipt, the underlying value of which is $1,000 principal amount of a fully paid Debenture.

Pursuant to rules and policy statements of certain Canadian securities regulators, the Underwriters may not, at any time during the period ending on the date the selling process for the Debentures represented by Instalment Receipts ends and all stabilization arrangements relating to the Debentures represented by Instalment Receipts are terminated, bid for or purchase Instalment Receipts, Debentures or Common Shares. The foregoing restrictions are subject to certain exceptions including: (i) a bid for or purchase made through the facilities of the TSX, in accordance with the Universal Market Integrity Rules of the Investment Industry Regulatory Organization of Canada; (ii) a bid or purchase on behalf of a client, other than certain prescribed clients, provided that the client's order was not solicited by the Underwriter, or if the client's order was solicited, the solicitation occurred before the commencement of a prescribed restricted period; and (iii) a bid or purchase to cover a short position entered into prior to the commencement of a prescribed restricted period. The Underwriters may engage in market stabilization or market balancing activities on the TSX where the bid for or purchase of the Instalment Receipts, Debentures or Common Shares is for the purpose of maintaining a fair and orderly market in the Instalment Receipts, Debentures or Common Shares, subject to price limitations applicable to such bids or purchases. Such transactions, if commenced, may be discontinued at any time.

The Debentures, the Instalment Receipts representing the Debentures, and the Common Shares into which the Debentures may be converted have not been, and will not be, registered under the United States *Securities Act of 1933*, as amended (the "1933 Act") or any state securities laws and, may not be offered, or delivered, directly or indirectly, or sold in the United States or to, or for the account or benefit of, U.S. persons (other than distributors) unless the Debentures represented by Instalment Receipts and the Common Shares into which the Debentures may be converted are registered under the 1933 Act or an exemption from the registration requirements of the 1933 Act and any applicable state securities laws is available. The Underwriters have agreed that they will not sell the Debentures represented by Instalment Receipts within the United States or to, or for the account or benefit of, any U.S. person, except in accordance with the Underwriting Agreement pursuant to the exemption from the registration requirements of the 1933 Act provided by Rule 144A thereunder and in compliance with applicable state securities laws. In addition, until 40 days after the commencement of the Offering, an offer or sale of Debentures represented by Instalment Receipts within the United States by any dealer (whether or not participating in the Offering) may violate the registration requirements of the 1933 Act if such offer or sale is made otherwise than in accordance with Rule 144A. When used in this section, the terms "United States", "U.S. person" and "distributor" have meanings ascribed to them in Regulation S under the 1933 Act ("Regulation S").

To comply with the requirements of Regulation S, any Underwriter and any other distributor selling Debentures represented by Instalment Receipts to a distributor, dealer or other person receiving a selling concession, fee or other remuneration in respect of the securities sold, prior to the expiration of 40 days after the closing of the offering of the Debentures represented by Instalment Receipts pursuant to this Prospectus, unless otherwise notified by the Corporation, must send to the purchaser a confirmation or other notice stating that the purchaser is subject to the same restrictions on offers and sales of the Debentures represented by Instalment Receipts that apply to such Underwriter or other distributor.

RELATIONSHIP BETWEEN FORTIS, THE SELLING DEBENTUREHOLDER AND CERTAIN UNDERWRITERS

Each of the Underwriters is a subsidiary of a Canadian chartered bank that has, either solely or as a member of a syndicate of financial institutions, extended (or will extend) credit facilities to, or holds (or will hold) other indebtedness of, the Corporation and/or its subsidiaries, including the Revolving Facility and the Acquisition Credit Facilities (collectively, the “Bank Indebtedness”). See “Financing the Acquisition” and “Capitalization”. In addition, Scotia Capital, RBC, TDSI and CIBC are acting as agents in the Concurrent Private Placement and will receive an agency fee in connection with such role pursuant to the Agency Agreement. See “Financing the Acquisition — Concurrent Private Placement”. Scotia Capital is also acting as financial advisor to Fortis in connection with the Acquisition and is receiving a fee therefor. Consequently, the Corporation may be considered a “connected issuer” of these Underwriters within the meaning of applicable securities legislation.

Except as described in “Use of Proceeds”, none of these Underwriters will receive any direct benefit from the Offering other than the underwriting commission relating to the Offering and the agency fee payable pursuant to the Agency Agreement in connection with the Concurrent Private Placement. The decision to distribute the Debentures hereunder and the determination of the terms of the Offering were made through negotiation between the Corporation, the Selling Debentureholder and the Underwriters. No bank had any involvement in such decision or determination. As at December 19, 2013, an aggregate of approximately $426 million was outstanding under the Bank Indebtedness. Fortis and/or its subsidiaries are in material compliance with their respective obligations under the Bank Indebtedness. Since entering into the Bank Indebtedness, no breach thereunder has been waived by the lenders thereof; there has been no material change in the financial position or condition of Fortis or its subsidiaries, except as otherwise described in this Prospectus (including in the documents incorporated by reference herein); and the value of any security for any such Bank Indebtedness has not changed, except in the ordinary course of business. See “Use of Proceeds”.

CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

In the opinion of Davies Ward Phillips & Vineberg LLP, counsel to Fortis and the Selling Debentureholder, and Stikeman Elliott LLP, counsel to the Underwriters, (collectively, “Counsel”) the following summary describes the principal Canadian federal income tax considerations pursuant to the Tax Act generally applicable to a holder who acquires Debentures represented by Instalment Receipts pursuant to this offering and who, for the purposes of the Tax Act and at all relevant times: (i) is resident, or is deemed to be resident, in Canada; (ii) holds the Debentures and will hold any Common Shares received on the conversion or maturity of the Debentures (collectively, the “Securities”) as capital property; (iii) deals at arm’s length with Fortis, the Selling Debentureholder and the Underwriters; and (iv) is not affiliated with the Corporation or the Selling Debentureholder (a “Holder”). Generally, the Securities will be considered to be capital property to a Holder provided the Holder does not hold the Securities in the course of carrying on a business and has not acquired them in one or more transactions considered to be an adventure or concern in the nature of trade. Certain Holders who might not otherwise be considered to hold their Securities as capital property may, in certain circumstances, be entitled to have the Securities, and all other “Canadian securities” (as defined in the Tax Act) owned by such holders in the taxation year of the election and all subsequent taxation years, deemed to be capital property by making the irrevocable election permitted by subsection 39(4) of the Tax Act. Holders are advised to consult their personal tax advisors to determine whether such an election is available and desirable in their particular circumstances.

This summary is not applicable to a Holder: (i) that is a “financial institution”, as defined in the Tax Act for the purposes of the mark-to-market rules; (ii) that is a “specified financial institution” as defined in the Tax Act; (iii) an interest which would be a “tax shelter investment” as defined in the Tax Act; (iv) that has elected to report its “Canadian tax results” in a currency other than the Canadian currency pursuant to the “functional currency” reporting rules, as all those terms are defined in the Tax Act; (v) that enters into a “derivative forward agreement” in respect of the Debentures or Common Shares, as defined in the Tax Act; or (vi) that is a corporation which is, or becomes as part of a series of transactions, controlled by a non-resident corporation and in respect of which a subsidiary of Fortis is, or would at any time be, a “foreign affiliate” (as defined in the Tax Act). Any such Holder should consult its own tax advisor with respect to an investment in the Securities.

This summary is based upon the provisions of the Tax Act in force as of the date hereof, all specific proposals to amend the Tax Act that have been publicly announced prior to the date hereof (the “Proposed Amendments”) and Counsel’s understanding of the current published administrative practices of the Canada Revenue Agency. This summary assumes that the Proposed Amendments will be enacted in the form proposed; however, no assurance can be given that the Proposed Amendments will be enacted in the form proposed, if at all. This summary is not exhaustive of all possible Canadian federal income tax considerations and, except for the Proposed Amendments, does not take into account any changes in the law, whether by legislative, governmental or judicial action, nor does it take into account provincial, territorial or foreign tax considerations, which may differ significantly from those discussed herein.

This summary is of a general nature only and is not intended to be, nor should it be construed to be, legal or tax advice to any particular Holder, and no representations with respect to the income tax consequences to any Holder are made. Consequently, Holders and prospective holders of Securities should consult their own tax advisors for advice with respect to the tax consequences to them of acquiring Securities pursuant to this offering, having regard to their particular circumstances. This summary does not address any tax considerations applicable to persons other than Holders and such persons should consult their own tax advisors regarding the consequences of acquiring, holding and disposing of Securities under the Tax Act and any jurisdiction in which they may be subject to tax.

Taxation of Interest on Debentures

A Holder of Debentures represented by Instalment Receipts that is a corporation, partnership, unit trust or any trust of which a corporation or a partnership is a beneficiary will be required to include in computing its income for a taxation year any interest on the Debentures that accrues to it to the end of the particular taxation year or that has become receivable by or is received by the Holder before the end of that taxation year, except to the extent that such interest was included in computing the Holder's income for a preceding taxation year. A "Canadian-controlled private corporation" (as defined in the Tax Act) also may be liable to pay a 6⅔% refundable tax on certain investment income including interest.

Any other Holder, including an individual, will be required to include in computing income for a taxation year all interest on the Debentures that is received or receivable by the Holder in that taxation year (depending upon the method regularly followed by the Holder in computing income), except to the extent that the interest was included in the Holder's income for a preceding taxation year.

Where, on acquisition of a Debenture represented by an Instalment Receipt, a Holder pays an amount on account of interest accrued on the Debenture to the date of acquisition, such amount may be deducted in computing the Holder's income in the taxation year in which, and to the extent that, the accrued interest is included in the Holder's income as interest. The adjusted cost base to the Holder of the Debenture represented by an Instalment Receipt will be reduced by the amount that is so deductible.

Any premium or bonus paid by the Corporation to a Holder because the Debenture is redeemed before the maturity thereof will be deemed to be interest received at that time by the Holder to the extent that such premium can reasonably be considered to relate to, and does not exceed the value at the time of the redemption of, the interest that would have been paid or payable on the Debenture for a taxation year ending after the redemption had the Debenture not been redeemed.

Exercise of Conversion Privilege

Generally, a Holder who converts a Debenture into Common Shares pursuant to the conversion privilege will be deemed not to have disposed of the Debenture (except for purposes of the deduction for interest included in income but not received as discussed below under "— Disposition of Debentures"). Accordingly, a Holder who converts a Debenture into Common Shares will not be considered to realize a capital gain (or capital loss) on such conversion. Under the current administrative practice of the Canada Revenue Agency, a Holder who, upon conversion of a Debenture, receives cash not in excess of $200 in lieu of a fraction of a Common Share may either treat this amount as proceeds of disposition of a portion of the Debenture, thereby realizing a capital gain (or capital loss), or reduce the adjusted cost base of the Common Shares that the Holder receives on the conversion by the amount of the cash received.

The aggregate cost to a Holder of Common Shares acquired on the conversion of a Debenture will generally be equal to the Holder's adjusted cost base of the Debenture immediately before the conversion. For the purposes of determining the adjusted cost base to a Holder of Common Shares at any time, the cost of such Common Shares will be averaged with the adjusted cost base of any other Common Shares owned by the Holder as capital property at the time.

Disposition of Debentures

A disposition or deemed disposition of a Debenture by a Holder, including upon redemption or at maturity but not including the conversion of a Debenture into Common Shares pursuant to the Holder's right of conversion as described above, will generally result in the Holder realizing a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition (adjusted as described below) are greater (or less) than the aggregate of the Holder's adjusted cost base thereof and any reasonable costs of disposition. Such capital gain (or capital loss) will be subject to the tax treatment described below under "— Taxation of Capital Gains and Capital Losses". In this regard, the cost to a Holder of a Debenture represented by an Instalment Receipt will include all amounts paid or payable by the Holder for such Debenture, including the amount of the final instalment, whether paid or unpaid. The proceeds of disposition to a Holder who disposes of a Debenture represented by an Instalment Receipt will include the amount of any unpaid final instalment.

Upon a disposition or deemed disposition, other than upon redemption or at maturity, interest accrued on the Debenture to the date of disposition will be included in computing the Holder's income for the year of disposition, except to the extent that it was included in computing the Holder's income for that or a preceding taxation year, and will be excluded from the Holder's proceeds of disposition of the Debenture. Where a Holder has disposed of a Debenture for consideration equal to its fair market value, the Holder will be entitled to deduct in computing income for the year of disposition any amount that has been included in the Holder's income as interest in respect of such Debenture for that year or any preceding taxation year to the extent such amount exceeds the amount received or receivable by the Holder in respect thereof. A conversion of a Debenture into Common Shares is a disposition for purposes of this rule.

If the Corporation pays the principal amount of the Debentures upon maturity by issuing Common Shares to the Holder, the Holder's proceeds of disposition of the Debenture will be equal to the fair market value, at the time of disposition of the Debenture, of the Common Shares and any other consideration so received (except any consideration received in satisfaction of accrued interest). The Holder's aggregate cost of the Common Shares so received will be equal to the fair market value of such Common Shares. For the purposes of determining the adjusted cost base to a Holder of the Common Shares at any time, the cost of such Common Shares will be averaged with the adjusted cost base of any other Common Shares owned by the Holder as capital property at that time.

Where a Debenture represented by an Instalment Receipt is forfeited to the Selling Debentureholder or is sold by the Custodian as a consequence of the Holder's failure to pay the final instalment, the Holder may be subject to special rules in the Tax Act relating to the seizure by a seller of property previously sold or the settlement or forgiveness of debt. Holders should consult their own tax advisors with respect to these special rules.

Receipt of Dividends on Common Shares

Dividends received or deemed to be received on Common Shares by a Holder who is an individual (other than certain trusts) will be included in computing the individual's income for tax purposes and will be subject to the gross-up and dividend tax credit rules normally applicable to dividends received from "taxable Canadian corporations" (as defined in the Tax Act), including the enhanced gross-up and dividend tax credit for "eligible dividends". A dividend will be an eligible dividend if the recipient receives written notice (which may include a notice published on the Corporation's website) from the Corporation designating the dividend as an "eligible dividend". There may be limitations on the ability of the Corporation to designate dividends as eligible dividends.

Taxable dividends received by an individual (including certain trusts) may give rise to a liability for alternative minimum tax as calculated under the detailed rules set out in the Tax Act.

A Holder that is a corporation will include dividends received or deemed to be received on Common Shares in computing its income for tax purposes and generally will be entitled to deduct the amount of such dividends in computing its taxable income, with the result that no tax will be payable by it in respect of such dividends.

Certain corporations, including a "private corporation" or a "subject corporation" (as such terms are defined in the Tax Act), may be liable to pay a refundable tax under Part IV of the Tax Act of 33⅓% on dividends received or deemed to be received on Common Shares to the extent such dividends are deductible in computing taxable income.

Disposition of Common Shares

A disposition or a deemed disposition of a Common Share by a Holder will generally result in the Holder realizing a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition of the Common Share are greater (or less) than the aggregate of the Holder's adjusted cost base thereof and any reasonable costs of disposition. Such capital gain (or capital loss) will be subject to the tax treatment described below under "— Taxation of Capital Gains and Capital Losses".

Taxation of Capital Gains and Capital Losses

Generally, one-half of any capital gain (a "taxable capital gain") realized by a Holder in a taxation year must be included in the Holder's income for the year, and one-half of any capital loss (an "allowable capital loss") realized by a Holder in a taxation year must be deducted from taxable capital gains realized by the Holder in that year. Allowable capital losses for a taxation year in excess of taxable capital gains for that year generally may be carried back and deducted in any of the three preceding taxation years or carried forward and deducted in any subsequent taxation year against net taxable capital gains realized in such years, to the extent and under the circumstances described in the Tax Act. Capital gains realized by an individual (including certain trusts) may give rise to a liability for alternative minimum tax as calculated under the detailed rules set out in the Tax Act. A "Canadian-controlled private corporation" (as defined in the Tax Act) also may be liable to pay a $6\frac{2}{3}$% refundable tax on certain investment income including taxable capital gains.

The amount of any capital loss realized by a Holder that is a corporation on the disposition of a Common Share may be reduced by the amount of dividends received or deemed to be received by it on such Common Share (or on a share for which the Common Share has been substituted) to the extent and under the circumstances described in the Tax Act. Analogous rules apply to a partnership or trust of which a corporation, trust or partnership is a member or beneficiary.

RISK FACTORS

An investment in: (i) the Debentures represented by Instalment Receipts pending payment of the final instalment; (ii) the Debentures following payment of the final instalment; and (iii) the Common Shares issuable upon the conversion of the Debentures, involves certain risks. A prospective purchaser of Debentures should carefully consider the risk factors described under:

(a) the heading "Business Risk Management" in the Annual MD&A as found on pages 49 to 66 of the Corporation's 2012 Annual Report;

(b) note 33 "Financial Risk Management" found on pages 136 to 139 in the Corporation's audited comparative consolidated financial statements as at December 31, 2012 and for the years ended December 31, 2012 and 2011, as contained in the Corporation's 2012 Annual Report; and

(c) note 20 "Financial Risk Management" found on pages F-26 to F-31 in the Corporation's unaudited comparative interim consolidated financial statements as at September 30, 2013 and for the three and nine months ended September 30, 2013 and 2012,

each of which is incorporated by reference herein. In addition, a prospective purchaser of Debentures should carefully consider the risk factors described in this section which relate to the Acquisition, the Instalment Receipts, the Debentures and the post-Acquisition business and operations of the Corporation and UNS Energy, as well as the other information contained in this Prospectus (including the documents incorporated by reference herein).

Risk Factors Relating to the Acquisition

Failure to complete the Acquisition

The closing of the Acquisition is subject to the normal commercial risks that the Acquisition will not close on the terms negotiated (including with respect to the consideration to be paid for each outstanding share of common stock of UNS Energy) or at all. The completion of the Acquisition is subject to receipt of UNS Energy Shareholder Approval and satisfaction of the other Approval Conditions, including obtaining the approval of each of the ACC and FERC, and the satisfaction or waiver of certain closing conditions contained in the Acquisition Agreement. The failure to obtain the required approvals or satisfy or waive the conditions contained in the Acquisition Agreement may result in the termination of the Acquisition Agreement. There is no assurance that such closing conditions will be satisfied or waived. Accordingly, there can be no assurance that Fortis will complete the Acquisition in the timeframe or on the basis described herein, if at all. The termination of the Acquisition Agreement may have a negative effect on the price of the Instalment Receipts, the Debentures and the Common Shares and will result in the redemption of the Debentures. If the closing of the Acquisition does not take place as contemplated, the Corporation could suffer adverse consequences, including the loss of investor confidence. See "The Acquisition Agreement — Closing Conditions".

The Cash Purchase Price could increase

UNS Energy is a public company and its directors owe fiduciary duties to UNS Energy which may require them to consider competing offers to purchase the common stock of UNS Energy as alternatives to the Acquisition. The Acquisition Agreement preserves the ability of the directors of UNS Energy to accept an alternative or competing offer in certain circumstances if such offer constitutes a Superior Proposal. If a Superior Proposal to acquire UNS Energy is made Fortis may exercise its right to match such offer and as a result the Cash Purchase Price may increase. See "The Acquisition Agreement".

Length of time required to complete the Acquisition is unknown

As described above under "— Failure to complete the Acquisition", the closing of the Acquisition is subject to the receipt of required shareholder and regulatory approvals and the satisfaction of other closing conditions contained in the Acquisition Agreement. There is no certainty, nor can Fortis provide any assurance, as to when these conditions will be satisfied, if at all. 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 or UNS Energy's business, financial condition or results of operations. Fortis intends to complete the Acquisition as soon as practicable after obtaining the required UNS Energy Shareholder Approval and regulatory approvals and satisfying the other required closing conditions. See "The Acquisition Agreement — Closing Conditions".

Fortis may not realize all of the anticipated benefits of the Acquisition

As described in "The Acquisition — Acquisition Rationale", Fortis believes that the Acquisition will provide benefits to the Corporation, including that the Acquisition will be accretive in the first full year following the closing of the Acquisition, excluding one-time 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 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. The challenge of integrating previously independent businesses makes evaluating the Corporation's business and future financial prospects difficult. The past financial performance of the Corporation may not be indicative of its future financial performance.

Failure to realize the anticipated benefits of the Acquisition 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 current rates or at all. The declaration of dividends by the Corporation is at the discretion of the Board of Directors and the Board of Directors may determine at any time to cease paying dividends. See "Dividend Policy" and "Risk Factors — Risk Factors Relating to the Post-Acquisition Business and Operations of the Corporation and UNS Energy".

Foreign exchange risk

The cash consideration for the Acquisition is required to be paid in U.S. dollars, while funds raised in the Offering, which will constitute a significant portion of the funds ultimately used to finance the Acquisition, are denominated in Canadian dollars. See "Use of Proceeds". As a result, increases in the value of the U.S. dollar versus the Canadian dollar prior to payment of the final instalment will increase the purchase price translated in Canadian dollars and thereby reduce the proportion of the purchase price for the Acquisition ultimately obtained by Fortis under this Offering.

In addition, the operations of UNS Energy are conducted in U.S. dollars. Following the Acquisition, the consolidated earnings and cash flows of Fortis will be impacted to a much greater extent by movements in the U.S. dollar relative to the Canadian dollar. To manage these risks, Fortis 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 illiquidity and, to the extent the applicable U.S. dollar depreciates against the Canadian dollar, the risk of using hedges could result in losses greater than if the hedging had not been used. Hedging arrangements may have the effect of limiting or reducing the total returns to Fortis 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.

Significant demands will be placed on the Corporation as a result of the Acquisition

As a result of the pursuit and completion of the Acquisition, significant demands will be placed on the Corporation's managerial, operational and financial personnel and systems. No assurance can be given that the Corporation's systems, procedures and controls will be adequate to support the expansion of the Corporation's operations resulting from the Acquisition. The Corporation's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to implement and improve its operational and financial controls and reporting systems.

Failure to pay final instalment will negatively impact the consolidated capitalization of the Corporation

Completion of the Acquisition is not conditional on the completion of this Offering by the Corporation or on the Corporation obtaining financing on favourable terms or at all. If a material amount due on payment of the final instalment is not paid by holders of Instalment Receipts and the Corporation is not able to quickly realize on the Debentures pledged to secure the obligation to pay the final instalment, the Corporation will not be able to use those proceeds to repay the Acquisition Credit Facilities. As a result, it may take Fortis longer than anticipated to repay the Acquisition Credit Facilities which may have a negative impact on the consolidated capitalization of Fortis until such time as the Acquisition Credit Facilities have been repaid by Fortis in full.

The Acquisition Credit Facilities may become unavailable

The commitment of the lenders to enter into the Acquisition Credit Facilities is subject to certain standard conditions which may result in such facilities becoming unavailable to Fortis in certain circumstances. If the Acquisition Credit Facilities become unavailable to Fortis, Fortis may not be able to complete the Acquisition. The inability of Fortis to complete the Acquisition will result in redemption of the Debentures. See "Financing the Acquisition — Acquisition Credit Facilities".

The Concurrent Private Placement may not be completed

Each of the Private Placement Subscribers has entered into a binding Subscription Agreement with the Corporation and the Selling Debentureholder, but such Subscription Agreements contain standard terms and conditions which may result in their termination prior to completion of the Concurrent Private Placement. In addition, one or more Private Placement Subscribers may breach the terms of their Subscription Agreement on or before the Closing Date or thereafter, resulting in non-payment of all or a portion of the price for the Private Placement Debentures or the final instalment with respect to such Private Placement Debentures. Any termination or non-completion with respect to any portion of the Concurrent Private Placement will have an adverse effect on the Corporation and any such termination or non-completion prior to the closing of the Offering will render certain disclosure in this Prospectus incorrect, potentially requiring the Corporation to file an amendment to the Prospectus, thereby delaying the closing of the Offering.

Fortis does not currently control UNS Energy and its subsidiaries

Although the Acquisition Agreement contains covenants on the part of UNS Energy regarding the operation of its business prior to closing the Acquisition, Fortis will not control UNS Energy and its subsidiaries until completion of the Acquisition and the UNS Energy business and results of operations may be adversely affected by events that are outside of the Corporation's control during the intervening period. Historic and current performance of UNS Energy's business and operations may not be indicative of success in future periods. The future performance of UNS Energy may be influenced by, among other factors, economic downturns, increased environmental regulation, turmoil in financial markets, unfavourable regulatory decisions, rising interest rates and other factors beyond the Corporation's control. As a result of any one or more of these factors, among others, the operations and financial performance of UNS Energy may be negatively affected which may adversely affect the future financial results of Fortis. See "Risk Factors — Risk Factors Relating to the Post-Acquisition Business and Operations of the Corporation and UNS Energy".

Fortis expects to incur significant Acquisition-Related Expenses

Fortis expects to incur a number of costs associated with completing the Acquisition. The substantial majority of these costs will be non-recurring expenses resulting from the Acquisition and will consist of transaction costs related to the Acquisition, including costs relating to the financing of the Acquisition and obtaining regulatory approval. Additional unanticipated costs may be incurred.

Information relating to UNS Energy in this Prospectus has been obtained from UNS Energy or its public disclosure record

All information relating to UNS Energy or its affiliates contained in this Prospectus has been provided to Fortis by UNS Energy or taken from the UNS Energy public disclosure record. Although the Corporation has conducted what it believes to be a prudent and thorough level of investigation in connection with the Acquisition and the disclosure relating to UNS Energy contained in this Prospectus, an unavoidable level of risk remains regarding the accuracy and completeness of such information. While Fortis has no reason to believe the information provided by UNS Energy or taken from the public disclosure record is misleading, untrue or incomplete, Fortis cannot assure the accuracy or completeness of such information nor can Fortis compel UNS Energy to disclose events which may have occurred or may affect the completeness or accuracy of such information but which are unknown to Fortis.

Risk Factors Relating to the Post-Acquisition Business and Operations of the Corporation and UNS Energy

Fortis will have a substantial amount of indebtedness which may adversely affect its cash flow and ability to operate its business

After giving effect to the Acquisition, Fortis will have a significant amount of debt, including US$1.8 billion of debt of UNS Energy assumed by Fortis as a result of the Acquisition. As of September 30, 2013, on a pro forma basis after giving effect to the Acquisition and other refinancing activities, but assuming conversion of all Debentures to Common Shares, details of which are included in the Capitalization table provided herein, Fortis would have approximately $10.3 billion of total indebtedness outstanding. The change in the capital structure of Fortis as a result of the Acquisition, the Offering, the Concurrent Private Placement and the entering into of the Acquisition Credit Facilities could cause credit rating agencies which rate the outstanding debt obligations of Fortis to re-evaluate and potentially downgrade the Corporation's current credit ratings, which could increase the Corporation's borrowing costs. See "Capitalization" and "Recent Developments".

The Corporation's historical and pro forma combined financial information may not be representative of the results of the Corporation following the Acquisition

The *pro forma* combined financial information included in this Prospectus has been prepared using the consolidated historical financial statements of Fortis and the consolidated historical financial statements of UNS Energy and does not purport to be indicative of the financial information that will result from the operations of Fortis on a consolidated basis following the Acquisition. In addition, the *pro forma* combined financial information included in this Prospectus is based in part on certain assumptions regarding the Acquisition that Fortis currently believes are reasonable. Fortis makes no assurances that its current assumptions will prove to be accurate over time. Accordingly, the historical and pro forma financial information included in this Prospectus does not necessarily represent the Corporation's results of operations and financial condition had Fortis and UNS Energy operated as a combined entity during the periods presented, or of the Corporation's results of operations and financial condition in the future. The Corporation's potential for future business success and operating profitability must be considered in light of the risks, uncertainties, expenses and difficulties typically encountered by recently combined companies.

In preparing the pro forma financial information contained in this Prospectus, Fortis has given effect to, among other items, the Offering, the Acquisition Credit Facilities, the completion of the Acquisition and the assumption of UNS Energy's outstanding indebtedness. Fortis has also assumed that the Debentures and the Private Placement Debentures will be converted into Common Shares on or immediately following the Final Instalment Date. While management believes that the estimates and assumptions underlying the pro forma financial information are reasonable, such assumptions and estimates may be materially different than the Corporation's actual experience following completion of the Acquisition. See also "Risk Factors — Risks Relating to the Acquisition". See the notes to the *pro forma* financial statements of Fortis incorporated in this Prospectus.

Potential undisclosed liabilities associated with the Acquisition

In connection with the Acquisition, there may be liabilities of UNS Energy and its subsidiaries that the Corporation failed to discover or was unable to quantify in the due diligence which it conducted prior to the execution of the Acquisition Agreement and the Corporation may not be indemnified for some or all of these liabilities. The discovery or quantification of any material liabilities of UNS Energy and its subsidiaries could have a material adverse effect on the Corporation's business, financial condition or future prospects.

Fortis may not be successful in retaining the services of certain key personnel of UNS Energy following the Acquisition

Fortis currently intends to retain certain key personnel of UNS Energy following the completion of the Acquisition to continue to manage and operate UNS Energy as a separate operating company. Fortis will compete with other potential employers for employees, and it may not be successful in keeping the services of the executives and other employees that it needs to realize the anticipated benefits of the Acquisition. The Corporation's failure to retain key personnel to remain as part of the management team of UNS Energy in the period following the Acquisition could have a material adverse effect on the business and operations of UNS Energy and Fortis on a consolidated basis.

Fortis is subject to risks associated with its results of operations and financing risks

Management of Fortis believes, based on its current expectations as to the Corporation's future performance (which reflects, among other things, the completion of the Acquisition), that the cash flow from its operations and funds available to it under its Revolving Facility and its ability to access capital markets will be adequate to enable the Corporation to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, expected revenue and the costs of planned capital expenditures are only estimates. Moreover, actual cash flows from operations are dependent on regulatory, market and other conditions that are beyond the control of the Corporation. As such, no assurance can be given that management's expectations as to future performance will be realized. In addition, management's expectations as to the Corporation's future performance reflect the current state of its information about UNS Energy and its operations and there can be no assurance that such information is correct and complete in all material respects.

The Corporation's degree of leverage could have adverse consequences for Fortis, particularly if a significant portion of the Acquisition Credit Facilities are drawn to complete the Acquisition or if a significant portion of the Debentures are not converted into Common Shares by the holders thereof. The significant increase in the degree of the Corporation's leverage could, among other things, limit the Corporation's ability to obtain additional financing for working capital, investment in subsidiaries, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; restrict the Corporation's flexibility and discretion to operate its business; limit the Corporation's ability to declare dividends on its Common Shares; require Fortis to dedicate a portion of cash flows from operations to the payment of interest on its existing indebtedness, in which case such cash flows will not be available for other purposes; cause ratings agencies to re-evaluate or downgrade the Corporations' existing credit ratings; expose Fortis to increased interest expense on borrowings at variable rates; limit the Corporation's ability to adjust to changing market conditions; place Fortis at a competitive disadvantage compared to its competitors that have less debt; make Fortis vulnerable to any downturn in general economic conditions; and render Fortis unable to make expenditures that are important to its future growth strategies.

Within the next five years (from September 30, 2013), approximately $2 billion of the Corporation's consolidated indebtedness will become due. Assuming the completion of the Acquisition, within the next five years (from September 30, 2013), approximately $2.7 billion of the Corporation's consolidated indebtedness will become due. Therefore, the Corporation will need to refinance or reimburse amounts outstanding under the Corporation's existing consolidated indebtedness. There can be no assurance that any indebtedness of the Corporation will be refinanced or that additional financing on commercially reasonable terms will be obtained, if at all. In the event that such indebtedness cannot be refinanced, or if it can be refinanced on terms that are less favourable than the current terms, the ability of the Corporation to declare dividends may be adversely affected.

The ability of the Corporation to meet its debt service requirements will depend on its ability to generate cash in the future, which depends on many factors, including the financial performance of the Corporation, debt service obligations, the realization of the anticipated benefits of the Acquisition and working capital and future capital expenditure requirements. In addition, the ability of the Corporation to borrow funds in the future to make payments on outstanding debt will depend on the satisfaction of covenants in existing credit agreements and other agreements. A failure to comply with any covenants or obligations under the Corporation's consolidated indebtedness could result in a default under one or more such instruments, which, if not cured or waived, could result in the termination of distributions by the Corporation and permit acceleration of the relevant indebtedness. If such indebtedness were to be accelerated, there can be no assurance that the assets of the Corporation would be sufficient to repay such indebtedness in full. There can also be no assurance that the Corporation will generate cash flow in amounts sufficient to pay outstanding indebtedness or to fund any other liquidity needs.

Jointly owned generating plants and generating plants operated by third parties

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. As a result of this reliance on other operators, TEP may not be able to ensure the proper management of the operations and maintenance of the plants. Further, TEP may have no ability or a limited ability to make determinations on how best to manage the changing environmental regime which affects such facilities. In addition, TEP will not have sole discretion as to how to proceed in the face of requirements relating to environmental compliance 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.

Pension and other employee benefit obligations of UNS Energy

UNS Energy's future benefit obligations to employees were estimated to be US$142 million (net of fair value of plan assets) as at September 30, 2013. Economic fluctuations could adversely impact the funding and expenses associated with these obligations and there can be no assurance that these pension and employee benefit obligations will not increase materially in the future, thereby negatively impacting UNS Energy's results of operations, net income and cash flows, and those of Fortis following the Acquisition.

National and local economic conditions can have a significant impact on the results of operations, net income and cash flows at UNS Energy and its subsidiaries

The business of UNS Energy and the UNS Utilities is concentrated in the State of Arizona. In recent years economic conditions in the State of Arizona have contributed significantly to a reduction in TEP's retail customer growth and lower energy usage by the company's residential, commercial and industrial customers. As a result of weak economic conditions, TEP's average retail customer base grew by less than 0.4% in each year from 2008 through 2012 compared with average increases of approximately 2% in each year from 2003 to 2007. In 2012, total retail kWh sales were 0.7% below 2011 levels. Similar impacts were felt at UNS Gas and UNS Electric. Annual average increases in the number of retail customers at both companies remained below 1% in 2008 through 2012 compared with average annual growth rates of 3% from 2003 to 2007. While it is expected that economic conditions in the State of 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, adversely affecting UNS Energy's results of operations, net income and cash flows and those of Fortis following the Acquisition.

Stranded assets

The coal-fired San Juan, Four Corners and Navajo generating stations in which TEP is a participant may be required to be closed before the end of their useful life due to recent changes in environmental regulation. Future changes in environmental regulation relating to CO_2 emissions may also further negatively impact the ability of the coal-fired generating plants from which TEP receives power to operate on an economically viable basis or at all. If any of the coal-fired generation plants from which TEP obtains power are closed prior to the end of their useful life, TEP could incur a material write-down of its assets and incur added expenses relating to the maintenance, decommissioning and cancellation of long-term coal contracts of such generating plants. Closure of any of such generating stations may force TEP to find higher cost replacement sources for the power it obtains from such generating facilities. TEP may not be permitted or entitled to seek reimbursement for such incremental increases in costs in the rates it charges its customers. See "The Acquired Business — Environmental Regulation".

New technological developments and the implementation of new Electric EE Standards will continue to have a significant impact on retail sales, which could negatively impact UNS Energy's results of operations, net income and cash flows

Heightened awareness of energy costs and environmental concerns has increased demand for products intended to reduce consumers' use of electricity. TEP and UNS Electric also are promoting DSM programs designed to help customers reduce their energy use and these efforts will increase significantly under energy efficiency rules approved in 2010 by the ACC and effective commencing in 2012. Unless the ACC makes a specific provision for the recovery of usage-based revenues lost to these energy efficiency programs, the reduced retail sales that could result from the success of these efforts could negatively impact the results of operations, net income and cash flows of TEP and UNS Electric and those of Fortis following the Acquisition.

Developments in technology could reduce demand for electricity

Research and development activities are ongoing for new technologies that produce power or reduce power consumption. These technologies include renewable energy, customer-oriented generation, energy efficiency and more energy efficient appliances and equipment. Advances in these, or other technologies, could reduce the cost of producing electricity or make the existing generating facilities of UNS Energy less economical. In addition, advances in such technologies could reduce electrical demand, which could negatively impact the results of operations, net income and cash flows of TEP and UNS Electric and those of Fortis following the Acquisition.

The revenues, results of operations and cash flows of the UNS Utilities are seasonal and are subject to weather conditions and customer usage patterns

TEP typically earns the majority of its operating revenue and net income in the third quarter because retail customers increase their air conditioning usage during the summer. Conversely, TEP's first quarter net income is typically limited by relatively mild winter weather in its retail service territory. UNS Electric's earnings follow a similar pattern, while UNS Gas' sales peak in the winter during home heating season. Cool summers or warm winters may reduce customer usage at all three companies, adversely affecting operating revenues, cash flows and net income by reducing sales.

The UNS Utilities are subject to regulation by the ACC, which sets the companies' retail rates and oversees many aspects of their business in ways that could negatively affect the companies' results of operations, net income and cash flows

The ACC is a regulatory body governed by the Arizona state constitution and is composed of five elected commissioners. Commissioners are elected state-wide for staggered four-year terms and are limited to serving a total of two terms. As a result, the composition of the commission and therefore its policies, are subject to change every two years.

The ACC is charged with setting retail electric and gas rates that provide utility companies in Arizona with an opportunity to recover their costs of service and earn a reasonable rate of return. ACC rate orders also regulate average cost of capital and the capital structure of the UNS Utilities, among other things, which limits the discretion of management in respect of the manner in which it runs such businesses. The decisions of these elected officials on such matters impact the net income and cash flows of the UNS Utilities.

In May 2013, the ACC initiated and subsequently closed an inquiry to discuss the possibility of opening Arizona to retail electric competition. If the ACC ultimately decides to implement retail electric competition in Arizona, it could negatively impact the results of operations, net income and cash flows of TEP and UNS Electric. See "The Acquired Business — Regulation".

Changes in U.S. federal energy regulation may negatively affect the results of operations, net income and cash flows of the UNS Utilities

The UNS Utilities are subject to the impact of comprehensive and changing governmental regulation at the federal level in the United States that continues to change the structure of the electric and gas utility industries and the ways in which these industries are regulated. The UNS Utilities are subject to regulation by FERC. FERC has jurisdiction over rates for electric transmission in interstate commerce and rates for wholesale sales of electric power, including terms and prices of transmission services and sales of electricity at wholesale prices. Changes in regulations by FERC may negatively affect the results of operations, net income and cash flows of the UNS Utilities.

The UNS Utilities are subject to numerous environmental laws and regulations that may increase their cost of operations or expose them to environmentally-related litigation and liabilities. Many of these regulations could have a significant impact on TEP due to its reliance on coal as its primary fuel for electricity generation

Numerous federal, state and local environmental laws and regulations in the United States and the State of Arizona affect present and future operations of UNS Energy's regulated utility subsidiaries. Those laws and regulations include rules regarding air emissions, water use, wastewater discharges, solid waste, hazardous waste and management of coal combustion residuals.

These laws and regulations can contribute to higher capital, operating and other costs, particularly with regard to enforcement efforts focused on existing power plants and new compliance standards related to new and existing power plants. These laws and regulations generally require TEP and UNS Electric to obtain and comply with a wide variety of environmental licenses, permits, authorizations and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations against UNS Energy and its regulated utility subsidiaries. Failure to comply with applicable laws and regulations may result in litigation, the imposition of civil or criminal fines and penalties and a requirement for costly equipment upgrades by regulatory authorities against UNS Energy and its regulated utility subsidiaries.

Existing environmental laws and regulations may be revised or new environmental laws and regulations may be adopted or become applicable to the facilities and operations of the UNS Utilities. Increased compliance costs or additional operating restrictions from revised or additional regulation could have an adverse effect on the results of operations of the UNS Utilities, particularly if those costs are not fully recoverable from customers. TEP's obligation to comply with the EPA's BART determinations as a participant in the San Juan, Four Corners and Navajo electricity generating plants, coupled with the financial impact of future climate change legislation, other environmental regulations and other business considerations, could jeopardize the economic viability of these electricity generating plants or the ability of individual participants to meet their obligations and continue their participation in these electricity generating plants. TEP cannot predict the ultimate outcome of these matters.

TEP also is contractually obligated to pay a portion of the environmental reclamation costs incurred at generating stations in which it has a minority interest and is obligated to pay similar costs at the coal mines that supply these generating stations. While TEP has recorded the portion of its obligations for such reclamation costs that can be determined at this time, the total costs for final reclamation at these sites are unknown and could be substantial.

New federal regulations to limit greenhouse gas emissions could increase TEP's cost of operations and result in a change in the composition of TEP's coal-dominated generating fleet

Based on the finding by the EPA in December 2009 that emissions of greenhouse gases endanger public health and welfare, the agency is in the process of regulating greenhouse gas emissions. In addition, there are proposals and ongoing studies at the state, federal and international levels to address global climate change that could also result in the regulation of CO_2 and other greenhouse gases. Any future regulatory actions taken to address global climate change represent a business risk to the operations of UNS Energy. In 2012, 72% of TEP's total energy resources came from its coal-fueled generating facilities.

Reductions in CO_2 emissions to the levels specified by some proposals could be materially adverse to the financial position or results of operations of UNS Energy if associated costs of control or limitation cannot be recovered from customers. In June 2013, President Obama directed the EPA to move forward with carbon emission regulations for both new and existing fossil-fueled power plants. For existing power plants, the President ordered the EPA to propose carbon emission standards by June 1, 2014, to finalize those standards by June 1, 2015 and to require states to submit their implementation plans to meet the standards by June 30, 2016. Changes to existing environmental laws applicable to the generating assets of TEP and UNS Electric could negatively impact the ability of certain of the generating plants to operate on an economically viable basis or at all and could result in significant capital expenditures being required to bring such plants into compliance with any new legislation. There is a particular risk that any new rules proposed by the EPA will significantly impair the ability to operate certain of TEP's coal-fired generation plants on an economically viable basis or at all. If any of the coal-fired generation plants from which TEP obtains power were closed prior to the end of their useful lives, TEP would likely be forced to find replacement sources for the power it obtains from such generating facilities at increased cost and could incur a material write-down of its assets. The impact of legislation or regulation to address global climate change would depend on the specific terms of those measures and cannot be determined at this time.

Failure to meet renewable energy standards and gas energy efficiency standards

The ACC's renewable energy standards require TEP and UNS Electric to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements in 2025. Further, in 2010, the ACC approved Gas EE Standards and Electric EE Standards which are designed to require TEP, UNS Gas and UNS Electric to implement cost-effective programs to reduce customers' energy consumption. There is a possibility that these renewable energy standards and gas efficiency standards will not be met which may result in regulatory sanctions and adverse financial consequences to TEP, UNS Gas or UNS Electric.

Volatility or disruptions in the financial markets may increase UNS Energy's financing costs, limit access to the credit markets and increase pension funding obligations, which may adversely affect UNS Energy's liquidity and ability to carry out its financial strategy

UNS Energy relies on access to the bank markets and capital markets as a significant source of liquidity and for capital requirements not satisfied by cash flow from operations. Market disruptions such as those experienced over the last four years in the United States and internationally may increase the cost of borrowing or adversely affect the ability of UNS Energy to access sources of liquidity needed to finance its operations and satisfy its obligations as they become due. These disruptions may include turmoil in the financial services industry, including substantial uncertainty surrounding particular lending institutions and counterparties UNS Energy does business with, unprecedented volatility in the markets where the outstanding securities of UNS Energy currently trade and general economic downturns in the UNS Energy regulated utility subsidiary service territories. If UNS Energy is unable to access credit at competitive rates, or if its borrowing costs dramatically increase, its ability to finance its operations, meet its short-term obligations and execute its financial strategy could be adversely affected.

Changing market conditions could negatively affect the market value of assets held in the pension and other retiree plans of UNS Energy and may increase the amount and accelerate the timing of required future funding contributions. See "— Pension and other employee benefit obligations of UNS Energy".

TEP, UNS Gas and UNS Electric are subject to wholesale credit risk

TEP, UNS Gas and UNS Electric are subject to credit risk related to their respective wholesale sales, purchases, procurement and hedging activities. This includes the risk of non-payment on power sales and delivery risk on power and gas purchases. All three companies have forward physical and financial contracts which may result in positive mark-to-market values which are subject to default risk. Significant levels of default or non-payment in connection with these activities would have an adverse impact on the financial condition of the UNS Utilities.

UNS Energy's net income and cash flows can be adversely affected by rising interest rates

As of February 13, 2013, TEP had US$215 million of tax-exempt variable rate debt obligations, US$50 million of which was hedged with a fixed-for-floating interest rate swap through September 2014. The variable interest rates are set weekly with maximum interest rates of 20% on US$178 million of debt obligations and 10% on the remaining US$37 million. The average weekly interest rate ranged from 0.06% to 0.26% in 2012.

UNS Energy, TEP, UNS Gas and UNS Electric also are subject to risk resulting from changes in the interest rate on their borrowings under revolving credit facilities. Revolving credit borrowings may be made on a spread over LIBOR or an Alternate Base Rate. Each of these agreements is a committed facility and expires in November 2016, subject to any rights of the lenders to terminate those facilities as a result of the Acquisition.

If capital market conditions result in rising interest rates, the resulting increase in the cost of variable rate borrowings would negatively impact UNS Energy's, TEP's, UNS Gas' and UNS Electric's results of operations, net income and cash flows.

TEP, UNS Gas and UNS Electric may be required to post margin under their power and fuel supply agreements, which could negatively impact their liquidity

TEP, UNS Gas and UNS Electric secure power and fuel supply resources to serve their respective retail customers. The agreements under which these regulated utilities contract for such resources include requirements to post credit enhancement in the form of cash or LOCs in certain circumstances, including changes in market prices of power and fuel supply which affect contract values, or a change in creditworthiness of the respective companies.

In order to post such credit enhancement, TEP, UNS Gas and UNS Electric would be required to use available cash, draw under their revolving credit agreements, or issue LOCs under their revolving credit agreements.

The maximum amount TEP may use under its revolving credit facility is US$200 million. As of September 30, 2013, TEP had US$199 million available to borrow under its revolving credit facility. The maximum amount UNS Gas or UNS Electric may borrow is US$70 million, so long as the combined amount drawn by both companies does not exceed US$100 million (the size of their combined borrowing capacity under the revolving credit facility). As of September 30, 2013, UNS Gas had US$70 million and UNS Electric had US$47 million, available to borrow under their revolving credit facility. From time to time, TEP, UNS Gas and UNS Electric use their respective revolving credit facilities to post collateral. If additional collateral is required, it may negatively impact TEP, UNS Gas and/or UNS Electric's ability to fund their capital requirements. As of September 30, 2013, TEP and UNS Electric each had posted less than US$1 million with counterparties in the form of cash or LOCs.

UNS Energy and its subsidiaries have debt which could adversely affect their business and results of operations

UNS Energy has no operations of its own and derives all of its revenues and cash flow from its subsidiaries. At December 31, 2012, the ratio of total debt (including capital lease obligations net of investments in lease debt) to total capitalization for UNS Energy and its subsidiaries was 63%. This debt level:

- requires UNS Energy and its subsidiaries to dedicate a substantial portion of their cash flow to pay principal and interest on their debt, which could reduce the funds available for working capital, capital expenditures and other general corporate purposes;
- could limit UNS Energy and its subsidiaries' ability to borrow additional amounts for working capital, capital expenditures, debt service requirements, execution of its business strategy or other purposes;
- could limit the ability of UNS Energy to pay dividends following the Acquisition; and
- could negatively impact the realization of the anticipated benefits of the Acquisition by Fortis.

The cost of purchasing TEP's leased assets and the cost of procuring alternate sources of generation or purchased power in 2015 could require significant outlays of cash in a short period of time, which could be difficult to finance

In August and October 2013, TEP exercised purchase options with respect to an additional aggregate 35.4% undivided interest in Springerville Unit 1 from the owner participants at an aggregate purchase price of approximately US$65.5 million, with the closing of the lease purchase options scheduled to occur in December 2014 and January 2015. In 2015, following the acquisition by TEP of the additional 35.4% interest in Springerville Unit 1 and the expiry of the Springerville Unit 1 Leases, the capacity received by TEP from this facility will be reduced to 49.5% of the continuous operating capability of Springerville Unit 1.

In August 2013, TEP entered into exclusive negotiations with Entegra to purchase Gila River, a natural gas-fired combined-cycle unit with a capacity rating of 550 MW. The purchase of Gila River, if completed, will replace foregone coal-fired leased capacity following expiry of the Springerville Unit 1 Leases.

The Springerville Coal Handling Facilities can be purchased in 2015 for a fixed price of US$120 million. TEP also leases a 50% undivided interest in the Springerville Common Facilities with primary lease terms ending in 2017 and 2021. Upon expiration of the Springerville Coal Handling Facilities Leases and Springerville Common Facilities Leases (whether at the end of the initial term or any renewal term), TEP has the obligation under agreements with the owners of Springerville Units 3 and 4 to purchase such facilities. Upon acquisition by TEP, the owner of Springerville Unit 3 has the option and the owner of Springerville Unit 4 has the obligation to purchase from TEP a 14% interest in the Common Facilities and a 17% interest in the Coal Handling Facilities.

The anticipated purchase by TEP of the additional 35.4% interest in Springerville Unit 1, Gila River and the Springerville Coal Handling Facilities in 2014 and 2015 will result in significant capital expenditures by TEP in a short period of time, which may be difficult to finance.

Regulatory rules and other restrictions could limit the ability of TEP, UNS Gas and UNS Electric to make distributions to UNS Energy

As a holding company, UNS Energy is dependent on the earnings and distributions of funds from its subsidiaries to service its debt. Several restrictions could preclude the ability of any of the UNS Utilities to transfer funds to UNS Energy, including the following:

- TEP, UNS Gas and UNS Electric are restricted from lending to affiliates or issuing securities without ACC approval;
- the Federal Power Act states that an electric utility's dividends shall not be paid out of funds properly included in capital accounts. Although TEP now has a positive balance of retained earnings as of September 30, 2013, TEP has historically had an accumulated deficit rather than positive retained earnings. UNS Energy currently believes that there is a reasonable basis for TEP to pay dividends from current year earnings even if it were to have an accumulated deficit. However, there can be no assurance that FERC would permit such dividend payments; and
- TEP, UNS Gas and UNS Electric must be in compliance with their respective debt agreements in order to make dividend payments to UNS Energy.

Restrictions of this nature could limit the ability of UNS Energy to pay dividends following the Acquisition and could negatively impact the realization of the anticipated benefits of the Acquisition by Fortis.

Unanticipated financing needs or reductions to net income could adversely impact the ability to comply with financial covenants in the UNS Energy, TEP and UNS Electric Credit Agreements

The UNS Energy, TEP and UNS Electric credit and reimbursement agreements include a maximum leverage ratio. The leverage ratios are calculated as the ratio of total indebtedness to total capital. The ability to comply with these covenants could be adversely impacted by unanticipated borrowing needs or unexpected charges to earnings or shareholder equity. In the event that UNS Energy, TEP or UNS Electric seek to renegotiate these provisions to provide additional flexibility, they may need to pay fees or increased interest rates on borrowings as a condition to any amendments or waivers.

The operation of electric generating stations involves risks that could result in unplanned outages or reduced generating capability that could adversely affect TEP's or UNS Electric's results of operations, net income, and cash flows

The operation of electric generating stations involves certain risks, including equipment breakdown or failure (due to wear and tear, latent defect, design error or operator error, among other things), 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 businesses of TEP and UNS Electric. There can be no assurance that the generation facilities of TEP or UNS Electric will continue to operate in accordance with expectations. If an unplanned outage or an equipment breakdown occurs, TEP or UNS Electric could be adversely affected. In addition, any applicable insurance coverage may not be adequate to protect the business of TEP and UNS Electric from material adverse effects as a result of such operational failures.

Operations may be adversely affected if water supply is materially reduced

Natural gas and coal-fired plants require continuous water flow for their operation. Shifts in weather or climate patterns, seasonable precipitation, the timing and rate of melting, run off, and other factors beyond the control of TEP and UNS Electric, may reduce the water flow to their generation facilities. Any material reduction in the water flow to such facilities would limit the ability of TEP and UNS Electric to produce and market electricity from such facilities and could have a material adverse effect on the business of each such company. Further, 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 TEP and UNS Electric operate could result in a material adverse effect on the business of each such company.

Disruption of fuel supply could have an adverse impact on the financial condition of the UNS Utilities

The UNS Utilities depend on third parties to supply fuel, including natural gas and coal. As a result, there are risks of supply interruptions and fuel price volatility, as fuel deliveries may not exactly match those required for energy sales or use in electricity production, due in part to the need to pre-purchase fuel inventories for reliability and dispatch requirements. Disruption of transportation services for fuel, whether because of weather-related problems, strikes, lock-outs, break-downs of locks and dams, pipeline failures or other events could impair the ability to deliver electricity or gas or generate electricity and could adversely affect operations. Further, the loss of coal suppliers or the inability to renew existing coal and natural gas contracts at favorable terms could significantly affect the ability to serve customers and have an adverse impact on the financial condition and results of operations of the UNS Utilities.

The facilities and operations of UNS Energy could be affected by natural disasters or other catastrophic events.

UNS Energy's facilities and operations are exposed to potential damage and partial or complete loss resulting from environmental disasters (e.g. floods, high winds, fires and earthquakes), equipment failures, vandalism, potentially catastrophic events such as a major accident or incident at one of the sites, and other events beyond the control of UNS Energy. The operation of transmission and distribution systems involves certain risks, including gas leaks, fires, explosions, pipeline ruptures and other hazards and risks that may cause unforeseen interruptions, personal injury or property damage. Any such incident could have an adverse effect on UNS Energy. In certain cases, there is potential that some events may not excuse UNS Energy and its utility subsidiaries from performing obligations pursuant to agreements with third parties.

TEP could be subject to higher costs and the possibility of significant penalties as a result of mandatory transmission standards

As a result of the Energy Policy Act of 2005, owners and operators of bulk power transmission systems, including TEP, are subject to mandatory transmission standards developed and enforced by NERC and subject to the oversight of FERC. Compliance with modified or new transmission standards may subject TEP to higher operating costs and increased capital costs. Failure to comply with the mandatory transmission standards could subject TEP to sanctions, including substantial monetary penalties.

UNS Energy may be subject to cyber-attacks and information security risks

As operators of critical energy infrastructure, UNS Energy and its regulated utility subsidiaries may face a heightened risk of cyber-attack and their corporate and information technology systems may be vulnerable to disability or failures as a result of unauthorized access due to hacking, viruses, acts of war or terrorism and other causes. In addition, the utility business requires access to sensitive customer data, including personal and credit information, in the ordinary course of business. If, despite the security measures of UNS Energy and its regulated utility subsidiaries, a significant or widely publicized breach occurred, UNS Energy and its regulated utility subsidiaries could have their operations disrupted, property damaged and customer information stolen, experience substantial loss of revenues, response costs and other financial loss; and be subject to increased regulation, litigation and damage to their reputation, any of which could have a negative impact on the business and results of operations of UNS Energy and its regulated utility subsidiaries.

TEP or UNS Electric might not be able to secure adequate rights-of-way to construct transmission lines and distribution related facilities and could be required to find alternate ways to provide adequate sources of energy and maintain reliable service for their customers

TEP and UNS Electric rely on federal, state and local governmental agencies and the Navajo Nation to secure right-of-way and siting permits to construct transmission lines and distribution-related facilities. If adequate right-of-way and siting permits to build new transmission lines cannot be secured:

- TEP and UNS Electric may need to rely on more costly alternatives to provide energy to their customers;
- TEP and UNS Electric may not be able to maintain reliability in their service areas; or
- TEP and UNS Electric's ability to provide electric service to new customers may be negatively impacted.

TEP and UNS Electric rely on transmission lines they do not own or control, which may hinder their ability to produce, sell and deliver electricity

TEP and UNS Electric depend on transmission and distribution facilities that are owned and operated by other utilities and power companies to deliver some of the electricity that they generate. An extended disruption in transmission, a failure in any such transmission system or a lack of available transmission and distribution facilities could impact the ability of TEP and UNS Electric to produce, sell and deliver electricity, which could result in a material adverse effect to the respective businesses of such companies.

Labour Relations

The organized employees of the UNS Energy utility subsidiaries are members of labour unions which have entered into collective bargaining agreements with their respective employer. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the business carried on by the UNS Energy utility subsidiaries. The UNS Energy utility subsidiaries consider their relationships with their respective labour unions to be satisfactory, but there can be no assurance that current relations will continue in future negotiations or that the terms under the present collective bargaining agreements will be renewed. Collective bargaining agreements covering certain employees of TEP, UNS Gas and UNS Electric expire in 2014, 2015 and 2016. The inability to maintain, or to renew the collective bargaining agreements on acceptable terms, could result in increased labour costs or service interruptions arising from labour disputes for the UNS Energy utility subsidiaries, which could have an adverse effect on the results of operations, cash flow and net income of such companies and on UNS Energy.

Underinsured and Uninsured Losses

UNS Energy and its utility subsidiaries maintain at all times insurance coverage in respect of potential liabilities and the accidental loss of value of certain of their assets from risks, in amounts considered appropriate, taking into account all relevant factors including the practices of owners of similar assets and operations. It is anticipated that such insurance coverage will be maintained. However, not all risks are covered by insurance and no assurance can be given that insurance will be consistently available or will be consistently available on economically feasible terms or that the amounts of insurance will be sufficient to cover losses or claims that may occur involving the assets or operations of UNS Energy or any of its utility subsidiaries.

Risk Factors Relating to the Instalment Receipts

Balance of Instalment Receipt purchase price remains outstanding and the failure of a holder of instalment receipts to pay the balance of the purchase price on or before the Final Instalment Date will have adverse consequences for the holder

Each Instalment Receipt purchased in the Offering represents an obligation of the holder of such security to pay $667 per $1,000 principal amount of Debentures on or before the Final Instalment Date. If the final instalment of the purchase price is not paid when due, the Defaulting Holder will no longer be able to pay the final instalment without the consent of the Selling Debentureholder. In addition, the Defaulting Holder will no longer be able to exercise the rights described under "Details of the Offering — Instalment Receipts — Rights and Privileges" and will cease to be entitled to any principal and the Make-Whole Payment (if applicable) in respect of the Debenture represented by such Instalment Receipt. In addition, if the holder of an Instalment Receipt does not pay the final instalment when due, the Debentures evidenced by such Instalment Receipt may, at the Selling Debentureholder's option, upon compliance with applicable law and the terms of the Instalment Receipt Agreement, be forfeited to the Selling Debentureholder in full satisfaction of the Defaulting Holder's obligations or such Debentures may be sold and the Defaulting Holder will remain liable for any deficiency in the proceeds of such sale. The Selling Debentureholder will have the right to and may commence legal action against Defaulting Holders who do not pay the final instalment on or before the Final Instalment Date. The commencement of any such litigation by the Selling Debentureholder may negatively affect the Corporation and the Selling Debentureholder, and could have an adverse effect on the price of the Debentures and the Common Shares.

There is currently no market through which the Instalment Receipts may be sold

There is currently no market through which the Instalment Receipts may be sold and purchasers of Debentures may not be able to resell Instalment Receipts. There can be no assurance that an active trading market will develop for the Instalment Receipts after the Offering or, if developed, that such a market will be sustained. This may affect the pricing of the Instalment Receipts in the secondary market, the transparency and availability of trading prices, the liquidity of Instalment Receipts, and the extent of issuer regulation. If an active market for the Instalment Receipts fails to develop or be sustained, the prices at which the Instalment Receipts trade may be adversely affected. Whether or not the Instalment Receipts will trade at lower prices depends on many factors, including liquidity of the Instalment

Receipts, prevailing interest rates and the market for similar securities, the market price of debt securities with maturities comparable to the Debentures, the market price of the Common Shares, general economic conditions and Fortis' financial condition, historic financial performance and future prospects.

The TSX has conditionally approved the listing of the Instalment Receipts (representing the Debentures and the Private Placement Debentures) and the Common Shares issuable on the conversion of the Debentures and Private Placement Debentures on the TSX, subject to Fortis fulfilling all of the requirements of the TSX on or before March 11, 2014. The Corporation has no current intention to list the Debentures or the Private Placement Debentures for trading on the TSX or any other exchange as it currently anticipates all Debentures and the Private Placement Debentures will be converted to Common Shares on the Final Instalment Date.

Fluctuations in trading price

An Instalment Receipt entitles the holder to unencumbered ownership of a Debenture upon payment of the final instalment on or before the Final Instalment Date. Interest rate movements will cause the value of debt instruments with a maturity comparable to the Debentures to fluctuate, and this will be reflected in the market price of the Instalment Receipts. The price volatility of the Instalment Receipts will be greater than the price volatility of debt instruments of a maturity comparable to the Debentures. This is due to the fact that the payment for the Instalment Receipts represents only 33.3% of the total principal amount payable for the underlying Debenture.

Further, the market price of the Common Shares underlying the Debentures may be volatile. This volatility may affect the ability of holders of Instalment Receipts to sell the Instalment Receipts at an advantageous price, particularly if the market price for Common Shares falls below the Conversion Price of Debentures represented by Instalment Receipts. In addition, it may result in greater volatility in the market price of the Instalment Receipts than would be expected for other debt securities or for non-convertible or non-exchangeable securities. Market price fluctuations in the Common Shares may be due to, among other things, the operating results of the Corporation failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, market perception of the likelihood of the completion of the Acquisition, adverse changes in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by Fortis, or by Fortis' competitors, along with a variety of additional factors. These broad market fluctuations may adversely affect the prices of the Instalment Receipts and the Common Shares.

Rights of holders of Instalment Receipts may change

Purchasers of Debentures will, prior to payment of the final instalment, be holders of Instalment Receipts and will be bound by the terms and conditions of the Instalment Receipt Agreement. The Instalment Receipt Agreement will provide that, pending payment of the final instalment, legal title to the Debentures offered hereby will be held by the Custodian on behalf of the Selling Debentureholder pursuant to the pledge to secure the payment of the final instalment. The terms and conditions of the Instalment Receipt Agreement may be amended in certain circumstances, including with the approval of holders of Instalment Receipts representing two-thirds of the principal amount of the Debentures represented thereby. The description of the Instalment Receipt Agreement contained in this Prospectus is qualified in its entirety by the provisions of such agreement, which should be reviewed by holders of Instalment Receipts. The Instalment Receipt Agreement will be filed by Fortis on SEDAR on the Closing Date.

Use of proceeds

There is no restriction on the ability of the Selling Debentureholder to use the proceeds of the Offering following closing of the Offering, both before and after the payment of the final instalment. Any such proceeds may be used by the Selling Debentureholder prior to the completion of the Acquisition for purposes unrelated to the Acquisition. Fortis currently expects that the aggregate amount of the final instalment will ultimately be used to repay amounts drawn under the Acquisition Credit Facilities and for other Acquisition-Related Expenses. See "Use of Proceeds".

Right to receive unencumbered Debentures may terminate

The Corporation has the obligation to redeem the Debentures at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the Approval Conditions will not be satisfied; (ii) termination of the Acquisition Agreement; and (iii) July 2, 2015 if the Final Instalment Notice has not been given on or before June 30, 2015. See "Details of the Offering — Debentures — Redemption". Accordingly, it is possible that Instalment Receipts will be outstanding for a very limited period of time. Upon such redemption, a holder will no longer be entitled to pay the final instalment or to receive any unencumbered Debentures and will only be entitled to receive a net payment equal to the redemption price less the amount of the final instalment otherwise payable by such holder to the Selling Debentureholder plus accrued and unpaid interest thereon. Until the Approval Conditions are satisfied and the Debentures are delivered to holders of Instalment Receipts pursuant to the Instalment Receipt Agreement, such holders have the rights described under "Details of the Offering — Instalment Receipts".

While the right of holders of Instalment Receipts to receive unencumbered Debentures may terminate as a result of a redemption by the Corporation of the Debentures as described herein, the Acquisition could potentially still be completed by the Corporation. If the Acquisition is completed following the redemption of the Debentures, holders of Instalment Receipts will not receive any of the benefits which may accrue to shareholders of the Corporation following completion of the Acquisition.

Acquisition may be completed on other terms

Both before and after payment of the final instalment, the Corporation may, in its sole discretion, amend the Acquisition Agreement and consummate the Acquisition on terms that may be substantially different from those contemplated in this Prospectus. Any such change will not affect the obligation of the holder of an Instalment Receipt to pay the final instalment on or before the Final Instalment Date. See "The Acquisition Agreement" and "Risk Factors — Risks Relating to the Acquisition — Failure to complete the Acquisition".

Risk Factors Relating to the Debentures

There is currently no market through which the Debentures may be sold

There is currently no market through which the Debentures may be sold and purchasers of Debentures may not be able to resell Debentures purchased under this Prospectus. The Corporation has not applied to list the Debentures for trading on the TSX, but has received conditional approval to list the Common Shares into which the Debentures may be converted. Accordingly, an investor who does not exercise the conversion privilege in respect of fully paid Debentures will be holding what Fortis expects will be highly illiquid securities. There can be no assurance that an active trading market will develop for the Debentures after payment of the final instalment or, if developed, that such a market will be sustained. This may affect the pricing of the Debentures in the secondary market, the transparency and availability of trading prices, the liquidity of Debentures, and the extent of issuer regulation. If an active market for the Debentures fails to develop or be sustained, the prices at which the Debentures trade may be adversely affected. Whether or not the Debentures will trade at lower prices depends on many factors, including, among others, liquidity of the Debentures, prevailing interest rates and the market for similar securities, the market price of the Common Shares, general economic conditions and the Corporation's financial condition, historic financial performance and future prospects.

Fluctuations in trading price

After the Final Instalment Date, Debentures will stop accruing interest. Accordingly, their value will be a function of the value of the underlying Common Share into which the Debenture is convertible. The market price of the Common Shares underlying the Debentures may be volatile. This volatility may affect the ability of holders of Debentures to sell the Debentures at an advantageous price. In addition, it may result in greater volatility in the market price of the Debentures than would be expected for other debt securities or non-convertible securities. Market price fluctuations in the Common Shares may be due to the operating results of the Corporation failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, market perception of the likelihood of the completion of the Acquisition, adverse changes in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by Fortis, or by Fortis' competitors, along with a variety of additional factors.

Existing and Prior Ranking Indebtedness

On the Closing Date the Corporation expects to have consolidated indebtedness of approximately $8.4 billion (including the Debentures). After giving effect to the Acquisition, assuming receipt of the aggregate total amount of the final instalment for each of the Debentures and the Private Placement Debentures and the use of such amounts to repay a portion of the Acquisition Credit Facilities, conversion of all Debentures and Private Placement Debentures into Common Shares and the assumption of UNS Energy's outstanding indebtedness, management estimates that the consolidated indebtedness of the Corporation will be $10.3 billion. See "Financing of the Acquisition" and "Capitalization".

The Debentures will be subordinate to all Senior Indebtedness of the Corporation. See "Details of the Offering — Debentures — Subordination". Therefore, in the event of the insolvency, bankruptcy, liquidation, reorganization, dissolution or winding up of the Corporation, the assets of the Corporation would be made available to satisfy its obligations with respect to the Debentures only after it has paid all of its secured creditors and all holders of senior indebtedness. Accordingly, all or a substantial portion of the Corporation's assets could be unavailable to satisfy the claims of holders of the Debentures. There may be insufficient assets remaining following such payments to pay amounts due on any or all of the Debentures then outstanding. See "Risk Factors — Risk Factors Relating to the Post-Acquisition Business and Operations of the Corporation and UNS Energy".

Absence of Covenant Protection

The Indenture does not restrict the Corporation or any of its subsidiaries from incurring additional indebtedness for borrowed money or otherwise from mortgaging, pledging or charging their properties to secure any indebtedness or other financing. The Indenture does not contain any provisions specifically intended to protect holders of the Debentures in the event of a future leveraged transaction involving the Corporation or any of its subsidiaries.

Rights of holders of Debentures may change

Holders of Debentures will be bound by the terms and conditions of the Indenture. The terms and conditions of the Indenture may be amended in certain circumstances, including with the approval of two-thirds of holders of outstanding Debentures. The description of the Indenture contained in this Prospectus is qualified in its entirety by the provisions of the Indenture, which should be reviewed by holders of Instalment Receipts and Debentures. The Indenture will be filed by Fortis on SEDAR on the Closing Date.

Redemption Prior to Maturity

The Debentures may be redeemed, at the option of the Corporation and without the consent of holders of Debentures, subject to certain conditions, after the Final Instalment Date and prior to the Maturity Date at a redemption price equal to the principal amount thereof, plus any unpaid interest which accrued prior to the Final Instalment Date, as described under "Details of the Offering — Debentures — Redemption".

The right of holders of Debentures to receive Common Shares will terminate as a result of a redemption by the Corporation of the Debentures as described herein. If a holder of Debentures has its Debentures redeemed by the Corporation following completion of the Acquisition, but prior to conversion by the holder of such Debentures into Common Shares, such holder will not receive any of the benefits which may accrue to shareholders of the Corporation following completion of the Acquisition. In addition, the redemption price of the Debentures may be worth less than the consideration obtained on a conversion of those Debentures by the holder thereof.

Conversion of Debentures following satisfaction of the Approval Conditions

Subject to satisfaction by the Corporation of the Approval Conditions and payment of the final instalment by the holder of an Instalment Receipt on or prior to the Final Instalment Date, such holder may convert its Debentures after the Final Instalment Date but prior to the earlier of the date of redemption or the Maturity Date. The Conversion Price will be $30.72 per Common Share, being a conversion rate of 32.5521 Common Shares per $1,000 principal amount of Debentures, subject to adjustment in certain circumstances. See "Details of the Offering — Debentures — Conversion Right". If the market price of the Common Shares is less than the Conversion Price, the trading price of the Debentures will be negatively impacted. If the market price of the Common Shares is less than the Conversion Price on the date of conversion by a holder, such holder will receive fewer Common Shares on conversion of its Debentures than they would be able to purchase with funds equal to the principal amount of its Debentures.

Interest on Debentures will cease to be payable prior to the Maturity Date

After giving the Final Instalment Notice, Fortis has the right, but not the obligation, to redeem any outstanding and unconverted Debentures at any time on or after the Final Instalment Date and prior to the Maturity Date, but may choose not to redeem such Debentures. Any unconverted Debentures outstanding on or after the day following the Final Instalment Date will cease to accrue interest. A holder who has not exercised its conversion privilege by such date will be holding a convertible debt security which no longer earns interest.

Credit risk

The likelihood that holders of the Debentures will receive payments owing to them under the terms of the Debentures will depend on the financial health of the Corporation and its creditworthiness. Although Fortis currently has an investment grade credit rating, there is no assurance the Corporation will have sufficient capital to repay the Debentures in cash on redemption or at the Maturity Date or that it will be able to raise sufficient capital on acceptable terms by the applicable redemption date or the Maturity Date to repay the outstanding Debentures. While Fortis has covenanted to maintain availability under its Revolving Facility of not less than $600,000,000, which is equal to one-third of the principal amount of the Debentures until the Final Instalment Date, there can be no certainty that the Revolving Facility will continue to be available at the time of redemption. The risk of default in any payment obligation by Fortis may increase to the extent that there is a significant decline in the price of the Common Shares.

No security or guarantees

The Debentures are unsecured obligations of the Corporation and are not secured by any of its assets or assets of any current or future subsidiaries of the Corporation.

Prevailing yields on similar securities

The prevailing yield on debt securities with comparable maturities will affect the market value of the Debentures. Assuming all other factors remain unchanged, the market value of the Debentures will decline as prevailing yields for similar securities rise, and will increase as prevailing yields for similar securities decline. The market value of the Debentures may also decline after the Debentures cease to accrue interest depending on the value of the underlying Common Shares.

Dilutive effects on shareholders

The issuance of Common Shares on conversion of the Debentures and the Private Placement Debentures may have a dilutive effect on shareholders of Fortis and an adverse impact on the price of the Common Shares, which may also adversely impact the price of the Debentures. Potential future offerings by Fortis of Common Shares or securities convertible into or exchangeable for Common Shares would dilute purchasers acquiring securities under this Prospectus.

Investment eligibility

The Corporation will endeavour to ensure that the Debentures represented by Instalment Receipts and the Common Shares continue to be qualified investments for Exempt Plans under the Tax Act, although there is no assurance that the conditions prescribed for such qualified investments will be adhered to at any particular time. The Tax Act imposes penalties for the acquisition or holding of non-qualified or prohibited investments.

Income tax matters

The income of the Corporation and its subsidiaries must be computed and is taxed in accordance with Canadian and other applicable tax laws, all of which may be changed in a manner that could adversely affect the amount of cash distributions. There can be no assurance that taxation authorities will accept the tax positions adopted by the Corporation or its subsidiaries, including their determinations of the amounts of income and capital taxes and the reasonableness of inter-company transfer prices, including interest charges, which could materially adversely affect cash positions of the Corporation or its subsidiaries, and holders of Debentures and the Common Shares.

AUDITORS

The auditors of the Corporation are Ernst & Young LLP, Chartered Accountants, The Fortis Building, 7th Floor, 139 Water Street, St. John’s, Newfoundland and Labrador A1C 1B2.

The auditors of UNS Energy and TEP are PricewaterhouseCoopers LLP, in Phoenix, Arizona. PricewaterhouseCoopers LLP is an independent registered public accounting firm that audited the financial statements of UNS Energy and TEP included in this Prospectus.

LEGAL MATTERS

Certain legal matters relating to this Offering will be passed upon on behalf of the Corporation and the Selling Debentureholder by Davies Ward Phillips & Vineberg LLP, Toronto and McInnes Cooper, St. John's and on behalf of the Underwriters by Stikeman Elliott LLP, Toronto. At the date hereof, partners and associates of each of Davies Ward Phillips & Vineberg LLP, McInnes Cooper and Stikeman Elliott LLP own beneficially, directly or indirectly, less than 1% of any securities of the Corporation or any associate or affiliate of the Corporation.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Instalment Receipts, the Debentures represented thereby and the Common Shares is Computershare Trust Company of Canada in Toronto and Montréal.

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revisions of the price or damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission, revisions of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal advisor.

Original purchasers of Debentures will have a contractual right of rescission against Fortis following the conversion of such Debentures in the event that this Prospectus or any amendment thereto contains a misrepresentation. The contractual right of rescission will entitle such original purchasers to receive from Fortis, upon surrender of the Common Shares issued upon conversion of such Debentures, the amount paid for such Debentures, provided that the right of rescission is exercised within 180 days from the date of the purchase of such Debentures under this Prospectus.

Original purchasers of Debentures are further cautioned that in an offering of convertible securities, such as the Debentures, the statutory right of action for damages for a misrepresentation contained in a prospectus is, under the securities legislation of certain provinces and territories, limited to the price at which the convertible security was offered to the public under the prospectus offering. Accordingly, any further payment made at the time of conversion of the security may not be recoverable in a statutory action for damages in such provinces or territories. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for the particulars of this right of action for damages or consult with a legal adviser.

ENFORCEABILITY OF CERTAIN CIVIL LIABILITIES

Mr. Frank Crothers, one of the Corporation's directors, resides outside of Canada and has appointed Fortis Inc., Suite 1201, 139 Water Street, St. John's, Newfoundland and Labrador A1B 3T2 as agent for service of process. Purchasers are advised that it may not be possible for investors to enforce judgments obtained in Canada against any person that resides outside of Canada, even if such person has appointed an agent for service of process.

GLOSSARY OF TERMS

In this Prospectus, unless the context otherwise requires, the following terms have the meanings set forth below.

"**1933 Act**" means the United States *Securities Act of 1933*, as amended.

"**2013 TEP Rate Order**" has the meaning ascribed thereto under the heading "The Acquired Business — Rates — TEP".

"**ACC**" means the Arizona Corporation Commission.

"**Acquisition**" means the acquisition by an indirect wholly owned subsidiary of Fortis of all of the issued and outstanding shares of UNS Energy pursuant to the terms of the Acquisition Agreement.

"**Acquisition Agreement**" has the meaning ascribed thereto on the cover page.

"**Acquisition Credit Agreement**" has the meaning ascribed thereto under the heading "Financing the Acquisition — Acquisition Credit Facilities".

"**Acquisition Credit Facilities**" has the meaning ascribed thereto under the heading "Prospectus Summary — Financing the Acquisition — Acquisition Credit Facilities".

"**Acquisition-Related Expenses**" means the estimated non-recurring costs, including related income tax effects and any governmental and other imposed costs, that may be incurred to consummate the Acquisition. Such costs, which will be fully expensed when incurred in accordance with US GAAP, include but are not limited to fees associated with financial advisory, consulting, accounting, tax, legal and other professional services, bridge facility commitment fees, costs associated with change of control and integration, out-of-pocket costs and other costs of a non-recurring nature.

"**Agency Agreement**" has the meaning ascribed thereto under the heading "Financing the Acquisition — Concurrent Private Placement".

"**AIF**" means the Annual Information Form of Fortis dated March 22, 2013 for the year ended December 31, 2012.

"**Algoma Power**" means Algoma Power Inc.

"**Annual MD&A**" means the Management Discussion and Analysis of financial condition and results of operations of Fortis for the year ended December 31, 2012 as contained in the Corporation's 2012 Annual Report.

"**Approval Conditions**" has the meaning ascribed thereto under the heading "Details of the Offering".

"**APS**" means the Arizona Public Service.

"**AUC**" has the meaning ascribed thereto under the heading "Recent Developments — FortisAlberta Capital Tracker Application".

"**Bank Indebtedness**" has the meaning ascribed thereto under the heading "Relationship Between Fortis, The Selling Debentureholder and Certain Underwriters".

"**BART**" has the meaning ascribed thereto under the heading "The Acquired Business — Environment Regulation — Regional Haze Rules".

"**BC Hydro**" means British Columbia Hydro and Power Authority.

"**BCUC**" means British Columbia Utilities Commission.

"**BECOL**" means Belize Electric Company Limited.

"**Belize Electricity**" means Belize Electricity Limited.

"**BMGS**" means the Black Mountain Generating Station.

"**BMO**" means BMO Nesbitt Burns Inc.

"**Board of Directors**" means the board of directors of Fortis.

"**Book-Entry Only System**" has the meaning ascribed thereto under the heading "Details of the Offering — Instalment Receipts — Book-Entry Only System".

"**CAGR**" means compound annual growth rate.

"**Capital Tracker Application**" has the meaning ascribed thereto under the heading "Recent Developments — FortisAlberta Capital Tracker Application".

"**Caribbean Utilities**" means Caribbean Utilities Company, Ltd.

"**Cash Purchase Price**" has the meaning ascribed thereto under the heading "The Acquisition Agreement — Purchase Price".

"**CC&N**" means a Certificate of Convenience and Necessity.

"**CCRs**" has the meaning ascribed thereto under the heading "The Acquired Business — Environmental Regulation — Coal Combustion Residuals".

"**CDS Participant**" means a participant in the CDS depository service.

"**CDS**" means CDS Clearing and Depository Services Inc.

"**Central Hudson**" means Central Hudson Gas & Electric Corporation.

"**CFIUS**" means the Committee on Foreign Investment in the United States.

"**CH Energy Acquisition**" has the meaning ascribed thereto under the heading "Recent Developments — Acquisition of CH Energy Group".

"**CH Energy Group**" means CH Energy Group, Inc.

"**CIBC**" means CIBC World Markets Inc.

"**Circuit Court**" means the Tenth Circuit United States Court of Appeals.

"**Closing Date**" has the meaning ascribed thereto on the cover page.

"**CNPI**" means Canadian Niagara Power Inc.

"**Common Shares**" means the common shares of Fortis.

"**Company Material Adverse Effect**" has the meaning ascribed thereto under the heading "The Acquisition Agreement — Closing Conditions".

"**Concurrent Private Placement**" has the meaning ascribed thereto under the heading "Financing the Acquisition — Concurrent Private Placement".

"**Conversion Price**" has the meaning ascribed thereto on the cover page.

"**Cornwall Electric**" means Cornwall Street Railway, Light and Power Company, Limited.

"**Corporation**" means Fortis Inc.

"**Counsel**" has the meaning ascribed thereto under the heading "Canadian Federal Income Tax Considerations".

"**CPC/CBT**" means Columbia Power Corporation and Columbia Basin Trust.

"**CSPP**" means the Consumer Share Purchase Plan of Fortis.

"**Custodian**" has the meaning ascribed thereto under the heading "Details of the Offering — Instalment Receipts".

"**DBRS**" means DBRS Limited.

"**Debentures**" means 4.00% convertible unsecured subordinated debentures of Fortis offered pursuant to this Prospectus.

"**Defaulting Holder**" has the meaning ascribed thereto under the heading "Details of the Offering — Instalment Receipts".

"**Desjardins Securities**" means Desjardins Securities Inc.

"**DPSP**" has the meaning ascribed thereto under the heading "Eligibility for Investment".

"**DRIP**" means the Dividend Reinvestment Plan of Fortis.

"**DSM**" means demand side management.

"**ECA**" means an Environmental Compliance Adjustor.

"**Electric EE Standards**" has the meaning ascribed thereto under the heading "The Acquired Business — Regulation — Electric Energy Efficiency Standards and Decoupling".

"**Entegra**" means Entegra Power Group LLC.

"**EPA**" means the United States Environmental Protection Agency.

"**EPNG**" means the El Paso Natural Gas Company.

"**ESP**" means energy service provider.

"**ESPP**" means the Employee Share Purchase Plan of Fortis.

"**Exempt Plans**" has the meaning ascribed thereto under the heading "Eligibility for Investment".

"**FEI**" means FortisBC Energy Inc.

"**FERC**" means the United States Federal Energy Regulatory Commission.

"**FEVI**" means FortisBC Energy (Vancouver Island) Inc.

"**FEWI**" means FortisBC Energy (Whistler) Inc.

"**Final Instalment Date**" has the meaning ascribed thereto under the heading "Details of the Offering".

"**Final Instalment Notice**" has the meaning ascribed thereto under the heading "Details of the Offering".

"**FIP**" has the meaning ascribed thereto under the heading "The Acquired Business — Environmental Regulation — Regional Haze Rules — San Juan".

"**First Preference Shares, Series E**" has the meaning ascribed thereto under the heading "Share Capital of Fortis".

"**First Preference Shares, Series F**" has the meaning ascribed thereto under the heading "Share Capital of Fortis".

"**First Preference Shares, Series G**" has the meaning ascribed thereto under the heading "Share Capital of Fortis".

"**First Preference Shares, Series H**" has the meaning ascribed thereto under the heading "Share Capital of Fortis".

"**First Preference Shares, Series J**" has the meaning ascribed thereto under the heading "Share Capital of Fortis".

"**First Preference Shares, Series K**" has the meaning ascribed thereto under the heading "Share Capital of Fortis".

"**Fortis**" means Fortis Inc.

"**FortisAlberta**" means FortisAlberta Inc.

"**FortisBC Holdings**" means FortisBC Holdings Inc.

"**FortisBC**" means FortisBC Inc.

"**FortisOntario**" means FortisOntario Inc.

"**FortisUS Energy**" means FortisUS Energy Corporation.

"Fortis Properties" means Fortis Properties Corporation.

"**Fortis Turks and Caicos**" means, collectively, FortisTCI Limited and its subsidiary Turks and Caicos Utilities Limited.

"**Four Corners**" means the Four Corners Generating Station.

"**FVRB**" means the Fair Value Rate Base.

"**Gas EE Standards**" has the meaning ascribed thereto under the heading "The Acquired Business — Regulation — Gas Energy Efficiency Standards and Decoupling".

"**GHG**" has the meaning ascribed thereto under the heading "The Acquired Business — Environmental Regulation — Climate Change".

"**Gila River**" has the meaning ascribed thereto under the heading "The Acquired Business — TEP — Future Generating Resources".

"**GOB**" means the Government of Belize.

"**Griffith Energy Services**" means Griffith Energy Services, Inc.

"**GWh**" means gigawatt hours.

"**Holder**" has the meaning ascribed thereto under the heading "Canadian Federal Income Tax Considerations".

"**IBEW**" means the International Brotherhood of Electrical Workers.

"**IFRS**" means International Financial Reporting Standards.

"**Indenture**" has the meaning ascribed thereto under the heading "Details of the Offering — Debentures".

"**Instalment Receipt Agreement**" has the meaning ascribed thereto under the heading "Details of the Offering — Instalment Receipts".

"**Instalment Receipts**" has the meaning ascribed thereto on the cover page.

"**kWh**" means kilowatt hour.

"**LFCR**" means the Lost Fixed Cost Recovery.

"**LIBOR**" has the meaning ascribed thereto under the heading "The Acquired Business — Outstanding Indebtedness — Credit Facilities".

"LNG" means liquefied natural gas.

"LOCs" means letters of credit.

"**Luna**" means the Luna Generating Station.

"**Make-Whole Payment**" has the meaning ascribed thereto on the cover page.

"**Management Information Circular**" means the Management Information Circular of Fortis dated March 21, 2013 prepared in connection with the Corporation's annual meeting of shareholders held on May 9, 2013.

"**Maritime Electric**" means Maritime Electric Company, Limited.

"Market Price" means the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days preceding the Maturity Date.

"**MATS**" means the EPA's Mercury and Air Toxics Standards.

"**Maturity Date**" means January 9, 2024.

"**Medium-Term Bridge Facility**" has the meaning ascribed thereto under the heading "Prospectus Summary — Financing the Acquisition — Acquisition Credit Facilities".

"**Millennium**" means Millennium Energy Holdings, Inc.

"**Moody's**" means Moody's Investor Services.

"**MW**" means megawatts.

"**Navajo**" means the Navajo Generating Station.

"**NB Financial**" means National Bank Financial Inc.

"**NERC**" means the North American Electric Reliability Corporation.

"**Newfoundland Hydro**" means Newfoundland and Labrador Hydro Corporation.

"**Newfoundland Power**" means Newfoundland Power Inc.

"**NO_X**" means nitrogen oxide.

“**NTUA**” means the Navajo Tribal Utility Authority.

“**NYSE**” means the New York Stock Exchange.

“**O&M**” has the meaning ascribed under the heading “The Acquired Business — Environmental Regulation — Clean Air Act Requirements”.

“**OCRB**” means the Original Cost Rate Base.

“**Offering**” the offering of Debentures pursuant to this Prospectus.

“**Offering Price**” means $1,000 per Debenture.

“**Operating Earnings**” means net earnings before corporate and other segment net expenses.

“**Over-Allotment Option**” has the meaning ascribed thereto on the cover page.

“**PBR**” means the performance-based rate.

“PGA” means Purchased Gas Adjustor.

“**PNM**” means the Public Service Company of New Mexico.

“**PPAs**” means power purchase agreements.

“**Private Placement Debentures**” has the meaning ascribed thereto under the heading “Financing the Acquisition — Concurrent Private Placement”.

“**Private Placement Subscriber**” has the meaning ascribed thereto under the heading “Financing the Acquisition — Concurrent Private Placement”.

“**Proposed Amendments**” has the meaning ascribed thereto under the heading “Canadian Federal Income Tax Considerations”.

“**Prospectus**” means this short form prospectus.

“**Purchaser**” has the meaning ascribed thereto under the heading “The Acquisition Agreement — Representations and Warranties”.

“**PV**” means photovoltaic solar generating capacity.

“**RBC**” means RBC Dominion Securities Inc.

“**Regulations**” means the regulations under the Tax Act.

“**Regulation S**” has the meaning ascribed thereto under the heading “Plan of Distribution”.

“**RES**” means the ACC’s Renewable Energy Standard.

“**Revolving Facility**” has the meaning ascribed thereto under the heading “Prospectus Summary — Financing the Acquisition — Acquisition Credit Facilities”.

“**ROE**” means the return on common shareholders’ equity.

“**RRIF**” has the meaning ascribed thereto under the heading “Eligibility for Investment”.

“**RRSP**” has the meaning ascribed thereto under the heading “Eligibility for Investment”.

“**Rules**” means the Retail Electric Competition Rules.

“**San Carlos**” means San Carlos Resources, Inc., a wholly owned subsidiary of TEP.

“**San Juan**” means the San Juan Generating Station.

“**Scotia Capital**” means Scotia Capital Inc.

“**SCR**” has the meaning ascribed thereto under the heading “The Acquired Business — Environment Regulation — Regional Haze Rules — Navajo”.

“**Securities**” has the meaning ascribed thereto under the heading “Canadian Federal Income Tax Considerations”.

"**SEDAR**" means the Canadian System for Electronic Document Analysis and Retrieval.

"**Selling Debentureholder**" means FortisUS Holdings Nova Scotia Limited.

"**Senior Indebtedness**" has the meaning ascribed thereto under the heading "Details of the Offering — Debentures — Subordination".

"**SES**" means Southwest Energy Solutions, Inc., a wholly owned subsidiary of Millennium.

"**Short-Term Bridge Facility**" has the meaning ascribed thereto under the heading "Prospectus Summary — Financing the Acquisition — Acquisition Credit Facilities".

"**SIP**" has the meaning ascribed thereto under the heading "The Acquired Business — Environmental Regulation — Regional Haze Rules — San Juan".

"**SNCR**" has the meaning ascribed thereto under the heading "The Acquired Business — Environmental Regulation — Regional Haze Rules — San Juan".

"**SO_2**" means sulfur dioxide.

"**Springerville**" means the Springerville Generating Station.

"**Springerville Coal Handling Facilities Leases**" has the meaning ascribed thereto under the heading "The Acquired Business — TEP — Generating and Other Resources — Springerville Generating Station".

"**Springerville Common Facilities**" has the meaning ascribed thereto under the heading "The Acquired Business — TEP — Generating and Other Resources — Springerville Generating Station".

"**Springerville Common Facilities Leases**" has the meaning ascribed thereto under the heading "The Acquired Business — TEP —

"**Springerville Unit 1 Leases**" has the meaning ascribed thereto under the heading "The Acquired Business — TEP — Generating and Other Resources — Springerville Generating Station".

"**SRP**" means the Salt River Project Agriculture Improvement and Power District.

"**Subscription Agreement**" has the meaning ascribed thereto under the heading "Financing the Acquisition — Concurrent Private Placement".

"**Sundt Station**" has the meaning ascribed thereto under the heading "The Acquired Business — TEP — Generating and Other Resources — Sundt Station and Sundt Internal Combustion Turbines".

"**Superior Proposal**" has the meaning ascribed thereto under the heading "The Acquisition Agreement — Superior Proposal".

"**Tax Act**" means the *Income Tax Act* (Canada) and the regulations thereunder.

"**TDSI**" means TD Securities Inc.

"**TEP**" means Tucson Electric Power Company.

"TEP Credit Facility" has the meaning ascribed thereto under the heading "The Acquired Business — Outstanding Indebtedness — Credit Facilities".

"**TEP LOC Facilities**" has the meaning ascribed thereto under the heading "The Acquired Business — Outstanding Indebtedness — Credit Facilities".

"**TFSA**" has the meaning ascribed thereto under the heading "Eligibility for Investment".

"**Tilbury LNG Facility**" has the meaning ascribed thereto under the heading "Recent Development — Tilbury LNG Facility Expansion".

"**TJ**" means terajoules.

"**Transwestern**" means Transwestern Pipeline Company.

"**Tri-State**" means Tri-State Generation and Transmission Association, Inc.

“**Trustee**” has the meaning ascribed thereto under the heading “Details of the Offering — Debentures”.

“**TSX**” means the Toronto Stock Exchange.

“**Underwriters**” has the meaning ascribed thereto under the heading “Plan of Distribution”.

“**Underwriting Agreement**” has the meaning ascribed thereto under the heading “Plan of Distribution”.

“**UNS Electric**” means UNS Electric Inc.

“**UNS Electric Term Loan**” has the meaning ascribed thereto under the heading “The Acquired Business — Outstanding Indebtedness — Credit Facilities”.

“**UNS Electric/UNS Gas Credit Facility**” has the meaning ascribed thereto under the heading “The Acquired Business — Outstanding Indebtedness — Credit Facilities”.

“**UNS Energy**” means UNS Energy Corporation.

“**UNS Energy Credit Facility**” has the meaning ascribed thereto under the heading “The Acquired Business — Outstanding Indebtedness — Credit Facilities”.

“**UniSource Energy Services**” means UniSource Energy Services, Inc.

“**UNS Energy Shareholder Approval**” has the meaning ascribed thereto under the heading “The Acquisition Agreement — Closing Conditions”.

“**UNS Gas**” means UNS Gas, Inc.

“**UNS Utilities**” means, collectively, TEP, UNS Electric and UNS Gas.

“**U.S. dollar**” has the meaning ascribed thereto under the heading “Currency”.

“**US GAAP**” means generally accepted and accounting principles in the United States.

“**Valencia**” means the Valencia Power Plant.

“**Waneta Expansion**” has the meaning ascribed thereto under the heading “Fortis — Non-Regulated — Fortis Generation — British Columbia”.

“**Waneta Partnership**” has the meaning ascribed thereto under the heading “Fortis”.

“**WAPA**” means Western Area Power Administration.

INDEX TO FINANCIAL STATEMENTS

(1) The Report of Independent Registered Public Accounting Firm on the consolidated financial statements of Tucson Electric Power Company, a wholly-owned subsidiary of UNS Energy Corporation, is also included.

(2) The financial statements of Tucson Electric Power Company are also included.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
UNS Energy Corporation:

In our opinion, the accompanying consolidated balance sheets and statements of capitalization and the related consolidated statements of income, comprehensive income, cash flows, and changes in stockholders' equity present fairly, in all material respects, the financial position of UNS Energy Corporation and its subsidiaries at December 31, 2012 and December 31, 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Phoenix, Arizona

February 26, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
Tucson Electric Power Company:

In our opinion, the accompanying consolidated balance sheets and statements of capitalization and the related consolidated statements of income, comprehensive income, cash flows, and changes in stockholder's equity present fairly, in all material respects, the financial position of Tucson Electric Power Company and its subsidiaries at December 31, 2012 and December 31, 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Phoenix, Arizona

February 26, 2013

UNS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2012	**2011**	**2010**
	- Thousands of Dollars - (Except Per Share Amounts)		
Operating Revenues			
Electric Retail Sales	**$1,087,279**	$1,085,822	$1,051,002
Electric Wholesale Sales	**125,414**	132,346	123,943
California Power Exchange (CPX) Provision for Wholesale Refunds	**—**	—	(2,970)
Gas Revenue	**123,133**	145,053	141,036
Other Revenues	**125,940**	115,481	112,936
Total Operating Revenues	**1,461,766**	1,478,702	1,425,947
Operating Expenses			
Fuel	**327,832**	324,520	295,652
Purchased Energy	**224,696**	276,610	279,269
Transmission	**14,540**	7,334	10,945
Increase (Decrease) to Reflect PPFAC/PGA Recovery Treatment	**32,246**	(4,932)	(29,622)
Total Fuel and Purchased Energy	**599,314**	603,532	556,244
Operations and Maintenance	**383,689**	379,220	370,037
Depreciation	**141,303**	133,832	128,215
Amortization	**35,784**	30,983	28,094
Taxes Other Than Income Taxes	**49,881**	49,428	46,243
Total Operating Expenses	**1,209,971**	1,196,995	1,128,833
Operating Income	**251,795**	281,707	297,114
Other Income (Deductions)			
Interest Income	**1,106**	4,568	7,779
Other Income	**7,085**	8,288	11,038
Other Expense	**(7,988)**	(5,279)	(15,202)
Total Other Income (Deductions)	**203**	7,577	3,615
Interest Expense			
Long-Term Debt	**71,909**	73,217	65,020
Capital Leases	**33,613**	40,359	46,740
Other Interest Expense	**1,983**	2,535	1,651
Interest Capitalized	**(2,153)**	(3,753)	(2,587)
Total Interest Expense	**105,352**	112,358	110,824
Income Before Income Taxes	**146,646**	176,926	189,905
Income Tax Expense	**55,727**	66,951	76,921
Net Income	**$ 90,919**	$ 109,975	$ 112,984
Weighted-Average Shares of Common Stock Outstanding (000)			
Basic	**40,362**	36,962	36,415
Diluted	**41,755**	41,609	41,041
Earnings per Share			
Basic	**$ 2.25**	$ 2.98	$ 3.10
Diluted	**$ 2.20**	$ 2.75	$ 2.86
Dividends Declared per Share	**$ 1.72**	$ 1.68	$ 1.56

See Notes to Consolidated Financial Statements.

UNS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2012	**2011**	**2010**
	-Thousands of Dollars-		
Comprehensive Income			
Net Income	**$90,919**	$109,975	$112,984
Other Comprehensive Income (Loss)			
Unrealized Loss on Cash Flow Hedges, net of $1,119, $2,376, and $4,216 income taxes	**(1,710)**	(3,626)	(6,431)
Reclassification of Realized Losses on Cash Flow Hedges to Net Income, net of $(1,862), $(1,412), and $(2,140) income taxes	**2,844**	2,153	3,264
SERP Benefit Adjustments, net of $608, $(804) and $523 income taxes	**(840)**	1,158	(800)
Total Other Comprehensive Income (Loss), Net of Income Taxes	**294**	(315)	(3,967)
Total Comprehensive Income	**$91,213**	$109,660	$109,017

See Notes to Consolidated Financial Statements.

UNS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2012	**2011**	**2010**
	- Thousands of Dollars -		
Cash Flows from Operating Activities			
Cash Receipts from Electric Retail Sales	**$1,197,390**	$1,163,537	$1,142,364
Cash Receipts from Electric Wholesale Sales	**149,722**	183,151	194,580
Cash Receipts from Gas Sales	**141,590**	159,529	157,397
Cash Receipts from Operating Springerville Units 3 & 4	**107,927**	104,754	102,563
Cash Receipts from Wholesale Gas Sales	**5,233**	12,404	422
Interest Received	**2,947**	6,334	10,026
Income Tax Refunds Received	**1,821**	4,672	341
Performance Deposits Received	**200**	7,050	18,470
Other Cash Receipts	**24,105**	23,937	32,011
Fuel Costs Paid	**(321,355)**	(277,386)	(243,639)
Payment of Operations and Maintenance Costs	**(291,512)**	(295,662)	(259,833)
Purchased Energy Costs Paid	**(250,231)**	(328,713)	(364,132)
Taxes Other Than Income Taxes Paid, Net of Amounts Capitalized	**(187,257)**	(179,766)	(163,037)
Wages Paid, Net of Amounts Capitalized	**(127,176)**	(122,370)	(125,893)
Interest Paid, Net of Amounts Capitalized	**(69,478)**	(68,027)	(59,749)
Capital Lease Interest Paid	**(28,788)**	(32,103)	(38,646)
Wholesale Gas Costs Paid	**—**	(11,822)	—
Performance Deposits Paid	**(200)**	(4,550)	(19,220)
Income Taxes Paid	**—**	(700)	(22,797)
Other Cash Payments	**(6,829)**	(6,949)	(14,308)
Net Cash Flows—Operating Activities	**348,109**	337,320	346,920
Cash Flows from Investing Activities			
Return of Investments in Springerville Lease Debt	**19,278**	38,353	25,615
Proceeds from Note Receivable	**15,000**	—	—
Other Cash Receipts	**22,094**	15,251	12,958
Capital Expenditures	**(307,277)**	(374,122)	(279,240)
Purchase of Intangibles—Renewable Energy Credits	**(10,317)**	(5,992)	(7,514)
Deposit—San Juan Mine Reclamation Trust	**(1,445)**	—	—
Purchase of Sundt Unit 4 Lease Asset	**—**	—	(51,389)
Other Cash Payments	**(232)**	(578)	(5,490)
Net Cash Flows—Investing Activities	**(262,899)**	(327,088)	(305,060)
Cash Flows from Financing Activities			
Proceeds from Borrowings Under Revolving Credit Facilities	**359,000**	391,000	239,000
Proceeds from Issuance of Long-Term Debt	**149,513**	340,285	127,815
Proceeds from Stock Options Exercised	**3,570**	8,115	13,391
Other Cash Receipts	**4,865**	4,743	12,406
Repayments of Borrowings Under Revolving Credit Facilities	**(381,000)**	(351,000)	(268,500)
Payments of Capital Lease Obligations	**(89,452)**	(74,381)	(55,997)
Common Stock Dividends Paid	**(69,648)**	(61,904)	(56,590)
Repayments of Long-Term Debt	**(9,341)**	(252,125)	(51,592)
Payments of Debt Issue/Retirement Costs	**(3,547)**	(4,361)	(8,341)
Other Cash Payments	**(1,642)**	(1,813)	(2,775)
Net Cash Flows—Financing Activities	**(37,682)**	(1,441)	(51,183)
Net Increase (Decrease) in Cash and Cash Equivalents	**47,528**	8,791	(9,323)
Cash and Cash Equivalents, Beginning of Year	**76,390**	67,599	76,922
Cash and Cash Equivalents, End of Year	**$ 123,918**	$ 76,390	$ 67,599
Non-Cash Financing Activity			
Repayment of UED Short-Term Debt	**$ —**	$ —	$ (3,188)

See Note 15 for supplemental cash flow information.

See Notes to Consolidated Financial Statements.

UNS ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2011
	-Thousands of Dollars-	
ASSETS		
Utility Plant		
Plant in Service	**$ 5,005,768**	$ 4,856,108
Utility Plant Under Capital Leases	**582,669**	582,669
Construction Work in Progress	**128,621**	89,749
Total Utility Plant	**5,717,058**	5,528,526
Less Accumulated Depreciation and Amortization	**(1,921,733)**	(1,869,300)
Less Accumulated Amortization of Capital Lease Assets	**(494,962)**	(476,963)
Total Utility Plant—Net	**3,300,363**	3,182,263
Investments and Other Property		
Investments in Lease Debt and Equity	**36,339**	65,829
Other	**36,537**	34,205
Total Investments and Other Property	**72,876**	100,034
Current Assets		
Cash and Cash Equivalents	**123,918**	76,390
Accounts Receivable—Customer	**93,742**	98,633
Unbilled Accounts Receivable	**53,568**	51,464
Allowance for Doubtful Accounts	**(6,545)**	(5,572)
Materials and Supplies	**93,322**	82,649
Fuel Inventory	**62,019**	33,263
Regulatory Assets—Current	**51,619**	97,056
Deferred Income Taxes—Current	**34,260**	23,158
Investments in Lease Debt	**9,118**	—
Derivative Instruments	**3,165**	11,966
Other	**33,567**	32,577
Total Current Assets	**551,753**	501,584
Regulatory and Other Assets		
Regulatory Assets—Noncurrent	**191,077**	173,199
Other Assets	**24,360**	32,199
Total Regulatory and Other Assets	**215,437**	205,398
Total Assets	**$ 4,140,429**	$ 3,989,279

See Notes to Consolidated Financial Statements.

UNS ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS — (Continued)

	December 31, 2012	December 31, 2011
	-Thousands of Dollars-	
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity	**$1,065,465**	$ 888,474
Capital Lease Obligations	**262,138**	352,720
Long-Term Debt	**1,498,442**	1,517,373
Total Capitalization	**2,826,045**	2,758,567
Current Liabilities		
Current Obligations Under Capital Leases	**90,583**	77,482
Borrowing Under Revolving Credit Facilities	**—**	10,000
Accounts Payable—Trade	**107,740**	109,760
Accrued Taxes Other than Income Taxes	**41,939**	41,997
Interest Accrued	**31,950**	38,302
Accrued Employee Expenses	**24,094**	25,660
Regulatory Liabilities—Current	**43,516**	41,911
Customer Deposits	**34,048**	32,485
Derivative Instruments	**14,742**	36,467
Other	**10,517**	8,455
Total Current Liabilities	**399,129**	422,519
Deferred Credits and Other Liabilities		
Deferred Income Taxes—Noncurrent	**364,756**	300,326
Regulatory Liabilities—Noncurrent	**279,111**	234,945
Pension and Other Retiree Benefits	**159,401**	139,356
Derivative Instruments	**12,709**	20,403
Other	**99,278**	113,163
Total Deferred Credits and Other Liabilities	**915,255**	808,193
Commitments, Contingencies, and Environmental Matters (Note 4)		
Total Capitalization and Other Liabilities	**$4,140,429**	$3,989,279

See Notes to Consolidated Financial Statements.

UNS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CAPITALIZATION

			December 31, 2012	December 31, 2011
			- Thousands of Dollars -	
COMMON STOCK EQUITY				
Common Stock-No Par Value			**$ 882,138**	$ 725,903
	2012	**2011**		
Shares Authorized	**75,000,000**	75,000,000		
Shares Outstanding	**41,343,851**	36,918,024		
Accumulated Earnings			**193,117**	172,655
Accumulated Other Comprehensive Loss			**(9,790)**	(10,084)
Total Common Stock Equity			**1,065,465**	888,474
PREFERRED STOCK				
No Par Value, 1,000,000 Shares Authorized, None Outstanding			**—**	—
CAPITAL LEASE OBLIGATIONS				
Springerville Unit 1			**196,843**	253,481
Springerville Coal Handling Facilities			**48,038**	65,022
Springerville Common Facilities			**107,840**	111,699
Total Capital Lease Obligations			**352,721**	430,202
Less Current Maturities			**(90,583)**	(77,482)
Total Long-Term Capital Lease Obligations			**262,138**	352,720
LONG-TERM DEBT				
Issue	**Maturity**	**Interest Rate**		
UNS Energy:				
Convertible Senior Notes	2035	4.50%	**—**	150,000
Credit Agreement	2016	Variable	**45,000**	57,000
Tucson Electric Power Company:				
Variable Rate Tax-Exempt Bonds	2014 – 2016	Variable	**215,300**	215,300
Unsecured Fixed Rate Bonds	2020 – 2040	4.50% – 6.38%	**609,320**	615,855
Unsecured Notes	2021 – 2023	3.85% – 5.15%	**398,822**	249,218
UNS Gas and UNS Electric:				
Senior Unsecured Notes	2015 – 2026	5.39% – 7.10%	**200,000**	200,000
UNS Electric:				
Unsecured Term Loan	2015	Variable	**30,000**	30,000
Total Long-Term Debt			**1,498,442**	1,517,373
Total Capitalization			**$2,826,045**	$2,758,567

See Notes to Consolidated Financial Statements.

UNS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	Common Shares Outstanding*	Common Stock	Accumulated Earnings	Accumulated Other Comprehensive Loss	Total Stockholders' Equity
			- Thousands of Dollars -		
Balances at December 31, 2009	**35,851**	**$696,206**	**$ 68,925**	**$ (5,802)**	**$ 759,329**
Comprehensive Income:					
2010 Net Income			112,984		112,984
Other Comprehensive Loss, net of $2,599 income taxes				(3,967)	(3,967)
Total Comprehensive Income					109,017
Dividends, Including Non-Cash Dividend Equivalents			(57,071)		(57,071)
Shares Issued under Deferred Compensation Plans	16	519			519
Shares Issued for Stock Options	660	12,756			12,756
Shares Issued Under Performance Share Awards	15	—			—
Other		6,206			6,206
Balances at December 31, 2010	**36,542**	**715,687**	**124,838**	**(9,769)**	**830,756**
Comprehensive Income:					
2011 Net Income			109,975		109,975
Other Comprehensive Loss, net of $160 income taxes				(315)	(315)
Total Comprehensive Income					109,660
Dividends, Including Non-Cash Dividend Equivalents			(62,158)		(62,158)
Shares Issued for Stock Options	319	8,176			8,176
Shares Issued Under Performance Share Awards	57	—			—
Other		2,040			2,040
Balances at December 31, 2011	**36,918**	**725,903**	**172,655**	**(10,084)**	**888,474**
Comprehensive Income:					
2012 Net Income			90,919		90,919
Other Comprehensive Income, net of $(135) income taxes				294	294
Total Comprehensive Income					91,213
Dividends, Including Non-Cash Dividend Equivalents			(70,457)		(70,457)
Shares Issued on Conversion of Notes and Related Tax Effect	4,262	149,805			149,805
Shares Issued for Stock Options	133	3,511			3,511
Shares Issued Under Performance Share Awards	31	—			—
Other		2,919			2,919
Balances at December 31, 2012	**41,344**	**$882,138**	**$193,117**	**$ (9,790)**	**$1,065,465**

* UNS Energy has 75 million authorized shares of Common Stock.

We describe limitations on our ability to pay dividends in Note 7.

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY

CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2012	**2011**	**2010**
	- Thousands of Dollars -		
Operating Revenues			
Electric Retail Sales	**$ 915,879**	$ 903,930	$ 868,188
Electric Wholesale Sales	**111,194**	129,861	141,103
California Power Exchange (CPX) Provision for Wholesale Refunds	**—**	—	(2,970)
Other Revenues	**134,587**	122,595	118,946
Total Operating Revenues	**1,161,660**	1,156,386	1,125,267
Operating Expenses			
Fuel	**318,901**	318,268	284,744
Purchased Power	**80,137**	105,766	118,716
Transmission	**5,722**	(1,435)	3,254
Increase (Decrease) to Reflect PPFAC Recovery Treatment	**31,113**	(6,165)	(21,541)
Total Fuel and Purchased Energy	**435,873**	416,434	385,173
Operations and Maintenance	**334,553**	330,801	316,625
Depreciation	**110,931**	104,894	99,510
Amortization	**39,493**	34,650	32,196
Taxes Other Than Income Taxes	**40,323**	40,199	37,732
Total Operating Expenses	**961,173**	926,978	871,236
Operating Income	**200,487**	229,408	254,031
Other Income (Deductions)			
Interest Income	**136**	3,567	6,707
Other Income	**6,043**	5,693	6,629
Other Expense	**(13,772)**	(12,064)	(11,506)
Total Other Income (Deductions)	**(7,593)**	(2,804)	1,830
Interest Expense			
Long-Term Debt	**55,038**	49,858	42,378
Capital Leases	**33,613**	40,358	46,734
Other Interest Expense	**1,446**	1,127	433
Interest Capitalized	**(1,782)**	(2,073)	(1,880)
Total Interest Expense	**88,315**	89,270	87,665
Income Before Income Taxes	**104,579**	137,334	168,196
Income Tax Expense	**39,109**	52,000	59,936
Net Income	**$ 65,470**	$ 85,334	$ 108,260

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2012	2011	2010
	-Thousands of Dollars-		
Comprehensive Income			
Net Income	**$65,470**	$85,334	$108,260
Other Comprehensive Income (Loss)			
Unrealized Loss on Cash Flow Hedges, net of $913, $2,331, and $4,216 income taxes	**(1,396)**	(3,555)	(6,431)
Reclassification of Realized Losses on Cash Flow Hedges to Net Income, net of $(1,800), $(1,390), and $(2,140) income taxes	**2,750**	2,122	3,264
SERP Benefit Adjustments, net of $608, $(804) and $523 income taxes	**(840)**	1,158	(800)
Total Other Comprehensive Income (Loss), Net of Income Taxes	**514**	(275)	(3,967)
Total Comprehensive Income	**$65,984**	$85,059	$104,293

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2012	**2011**	**2010**
	- Thousands of Dollars -		
Cash Flows from Operating Activities			
Cash Receipts from Electric Retail Sales	**$1,006,926**	$ 963,247	$ 947,498
Cash Receipts from Electric Wholesale Sales	**124,594**	152,618	190,779
Cash Receipts from Operating Springerville Units 3 & 4	**107,927**	104,754	102,563
Reimbursement of Affiliate Charges	**20,926**	18,448	18,356
Cash Receipts from Wholesale Gas Sales	**4,652**	11,825	—
Interest Received	**2,025**	5,367	8,998
Income Tax Refunds Received	**493**	7,492	3,369
Other Cash Receipts	**18,850**	19,611	23,429
Fuel Costs Paid	**(313,742)**	(271,975)	(232,591)
Payment of Operations and Maintenance Costs	**(282,752)**	(287,615)	(248,895)
Taxes Other Than Income Taxes Paid, Net of Amounts Capitalized	**(147,859)**	(139,728)	(134,540)
Wages Paid, Net of Amounts Capitalized	**(104,955)**	(100,942)	(101,815)
Purchased Power Costs Paid	**(81,328)**	(117,224)	(169,658)
Interest Paid, Net of Amounts Capitalized	**(52,125)**	(45,433)	(38,232)
Capital Lease Interest Paid	**(28,786)**	(32,103)	(38,640)
Income Taxes Paid	**(1,796)**	(2,346)	(19,663)
Wholesale Gas Costs Paid	**—**	(11,822)	—
Other Cash Payments	**(5,131)**	(5,880)	(8,475)
Net Cash Flows—Operating Activities	**267,919**	268,294	302,483
Cash Flows from Investing Activities			
Return of Investments in Springerville Lease Debt	**19,278**	38,353	25,615
Other Cash Receipts	**15,957**	7,195	8,044
Capital Expenditures	**(252,782)**	(351,890)	(225,920)
Purchase of Intangibles—Renewable Energy Credits	**(8,889)**	(5,111)	(7,903)
Deposit—San Juan Mine Reclamation Trust	**(1,445)**	—	—
Purchase of Sundt Unit 4 Lease Asset	**—**	—	(51,389)
Other Cash Payments	**—**	(558)	(1,483)
Net Cash Flows—Investing Activities	**(227,881)**	(312,011)	(253,036)
Cash Flows from Financing Activities			
Proceeds from Borrowings Under Revolving Credit Facility	**189,000**	220,000	177,000
Proceeds from Issuance of Long-Term Debt	**149,513**	260,285	118,245
Equity Investment from UNS Energy	**—**	30,000	15,000
Other Cash Receipts	**3,132**	2,458	3,241
Repayments of Borrowings Under Revolving Credit Facility	**(199,000)**	(210,000)	(212,000)
Payments of Capital Lease Obligations	**(89,452)**	(74,343)	(55,889)
Dividends Paid to UNS Energy	**(30,000)**	—	(60,000)
Repayments of Long-Term Debt	**(6,535)**	(172,460)	(30,000)
Payments of Debt Issue/Retirement Costs	**(3,547)**	(3,594)	(5,988)
Other Cash Payments	**(1,124)**	(894)	(1,491)
Net Cash Flows—Financing Activities	**11,987**	51,452	(51,882)
Net Increase (Decrease) in Cash and Cash Equivalents	**52,025**	7,735	(2,435)
Cash and Cash Equivalents, Beginning of Year	**27,718**	19,983	22,418
Cash and Cash Equivalents, End of Year	**$ 79,743**	$ 27,718	$ 19,983

See Note 15 for supplemental cash flow information.

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY

CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2011
	- Thousands of Dollars -	
ASSETS		
Utility Plant		
Plant in Service	**$ 4,348,041**	$ 4,222,236
Utility Plant Under Capital Leases	**582,669**	582,669
Construction Work in Progress	**98,460**	76,517
Total Utility Plant	**5,029,170**	4,881,422
Less Accumulated Depreciation and Amortization	**(1,783,787)**	(1,753,807)
Less Accumulated Amortization of Capital Lease Assets	**(494,962)**	(476,963)
Total Utility Plant—Net	**2,750,421**	2,650,652
Investments and Other Property		
Investments in Lease Debt and Equity	**36,339**	65,829
Other	**35,091**	32,313
Total Investments and Other Property	**71,430**	98,142
Current Assets		
Cash and Cash Equivalents	**79,743**	27,718
Accounts Receivable—Customer	**71,813**	73,612
Unbilled Accounts Receivable	**33,782**	32,386
Allowance for Doubtful Accounts	**(4,598)**	(3,766)
Accounts Receivable—Due from Affiliates	**5,720**	4,049
Materials and Supplies	**80,377**	70,749
Fuel Inventory	**61,737**	32,981
Deferred Income Taxes—Current	**37,212**	21,678
Regulatory Assets—Current	**34,345**	71,747
Investments in Lease Debt	**9,118**	—
Other	**34,393**	15,192
Total Current Assets	**443,642**	346,346
Regulatory and Other Assets		
Regulatory Assets—Noncurrent	**178,330**	157,386
Other Assets	**17,223**	25,135
Total Regulatory and Other Assets	**195,553**	182,521
Total Assets	**$ 3,461,046**	$ 3,277,661

See Notes to Consolidated Financial Statements.

(Consolidated Balance Sheets Continued)

TUCSON ELECTRIC POWER COMPANY

CONSOLIDATED BALANCE SHEETS

	December 31,	
	2012	2011
	- Thousands of Dollars -	
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity	**$ 860,927**	$ 824,943
Capital Lease Obligations	**262,138**	352,720
Long-Term Debt	**1,223,442**	1,080,373
Total Capitalization	**2,346,507**	2,258,036
Current Liabilities		
Current Obligations Under Capital Leases	**90,583**	77,482
Borrowing Under Revolving Credit Facility	**—**	10,000
Accounts Payable—Trade	**82,122**	84,509
Accounts Payable—Due to Affiliates	**3,134**	4,827
Accrued Taxes Other than Income Taxes	**33,060**	32,155
Interest Accrued	**26,965**	30,877
Accrued Employee Expenses	**20,715**	22,099
Customer Deposits	**24,846**	23,743
Regulatory Liabilities—Current	**20,822**	23,702
Derivative Instruments	**4,899**	9,040
Other	**7,085**	5,957
Total Current Liabilities	**314,231**	324,391
Deferred Credits and Other Liabilities		
Deferred Income Taxes—Noncurrent	**319,216**	263,225
Regulatory Liabilities—Noncurrent	**241,189**	200,599
Pension and Other Retiree Benefits	**149,718**	130,660
Derivative Instruments	**10,565**	14,142
Other	**79,620**	86,608
Total Deferred Credits and Other Liabilities	**800,308**	695,234
Commitments, Contingencies, and Environmental Matters (Note 4)		
Total Capitalization and Other Liabilities	**$3,461,046**	$3,277,661

See Notes to Consolidated Financial Statements.

(Consolidated Balance Sheets Concluded)

TUCSON ELECTRIC POWER COMPANY

CONSOLIDATED STATEMENTS OF CAPITALIZATION

			December 31, 2012	December 31, 2011
			- Thousands of Dollars -	
COMMON STOCK EQUITY				
Common Stock-No Par Value			**$ 888,971**	$ 888,971
	2012	2011		
Shares Authorized	**75,000,000**	75,000,000		
Shares Outstanding	**32,139,434**	32,139,434		
Capital Stock Expense			**(6,357)**	(6,357)
Accumulated Deficit			**(12,157)**	(47,627)
Accumulated Other Comprehensive Loss			**(9,530)**	(10,044)
Total Common Stock Equity			**860,927**	824,943
PREFERRED STOCK				
No Par Value, 1,000,000 Shares Authorized, None Outstanding			**—**	—
CAPITAL LEASE OBLIGATIONS				
Springerville Unit 1			**196,843**	253,481
Springerville Coal Handling Facilities			**48,038**	65,022
Springerville Common Facilities			**107,840**	111,699
Total Capital Lease Obligations			**352,721**	430,202
Less Current Maturities			**(90,583)**	(77,482)
Total Long-Term Capital Lease Obligations			**262,138**	352,720
LONG-TERM DEBT				
Issue	**Maturity**	**Interest Rate**		
Variable Rate Tax-Exempt Bonds	2014 – 2016	Variable	**215,300**	215,300
Unsecured Fixed Rate Bonds	2020 – 2040	4.50% – 6.38%	**609,320**	615,855
Unsecured Notes	2021 – 2023	3.85% – 5.15%	**398,822**	249,218
Total Long-Term Debt			**1,223,442**	1,080,373
Total Capitalization			**$2,346,507**	$2,258,036

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDER'S EQUITY

	Common Stock	Capital Stock Expense	Accumulated Deficit	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
Balances at December 31, 2009	**$843,971**	**$(6,357)**	**$(181,221)**	**$ (5,802)**	**$650,591**
Comprehensive Income:					
2010 Net Income			108,260		108,260
Other Comprehensive Loss, net of $2,599 income taxes				(3,967)	(3,967)
Total Comprehensive Income					104,293
Capital Contribution from UNS Energy	15,000				15,000
Dividends Paid			(60,000)		(60,000)
Balances at December 31, 2010	**858,971**	**(6,357)**	**(132,961)**	**(9,769)**	**709,884**
Comprehensive Income:					
2011 Net Income			85,334		85,334
Other Comprehensive Loss, net of $137 income taxes				(275)	(275)
Total Comprehensive Income					85,059
Capital Contribution from UNS Energy	30,000				30,000
Balances at December 31, 2011	**888,971**	**(6,357)**	**(47,627)**	**(10,044)**	**824,943**
Comprehensive Income:					
2012 Net Income			65,470		65,470
Other Comprehensive Income, net of $(279) income taxes				514	514
Total Comprehensive Income					65,984
Dividends Paid			(30,000)		(30,000)
Balances at December 31, 2012	**$888,971**	**$(6,357)**	**$ (12,157)**	**$ (9,530)**	**$860,927**

We describe limitations on our ability to pay dividends in Note 7.

See Notes to Consolidated Financial Statements.

NOTE 1. NATURE OF OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

NATURE OF OPERATIONS

UNS Energy Corporation (UNS Energy), formerly UniSource Energy Corporation, is a utility services holding company engaged, through its subsidiaries, in the electric generation and energy delivery business. Each of UNS Energy's subsidiaries is a separate legal entity with its own assets and liabilities. UNS Energy owns 100% of Tucson Electric Power Company (TEP), UniSource Energy Services, Inc. (UES), Millennium Energy Holdings, Inc. (Millennium), and UniSource Energy Development Company (UED).

TEP is a regulated public utility and UNS Energy's largest operating subsidiary, representing approximately 84% of UNS Energy's total assets as of December 31, 2012. TEP generates, transmits and distributes electricity to approximately 406,000 retail electric customers in a 1,155 square mile area in southeastern Arizona. TEP also sells electricity to other utilities and power marketing entities, located primarily in the western United States. In addition, TEP operates Springerville Generating Station (Springerville) Unit 3 on behalf of Tri-State Generation and Transmission Association, Inc. (Tri-State) and Springerville Unit 4 on behalf of Salt River Project Agriculture Improvement and Power District (SRP).

UES holds the common stock of two regulated public utilities, UNS Gas, Inc. (UNS Gas) and UNS Electric, Inc. (UNS Electric). UNS Gas is a regulated gas distribution company, which services approximately 149,000 retail customers in Mohave, Yavapai, Coconino, and Navajo counties in northern Arizona, as well as in Santa Cruz County in southern Arizona. UNS Electric is a regulated public utility, which generates, transmits and distributes electricity to approximately 92,000 retail customers in Mohave and Santa Cruz counties.

UED and Millennium's investments in unregulated businesses represent less than 1% of UNS Energy's assets as of December 31, 2012.

Our business is comprised of three reporting segments – TEP, UNS Gas, and UNS Electric.

References to "we" and "our" are to UNS Energy and its subsidiaries, collectively.

REVISION OF PRIOR PERIOD FINANCIAL STATEMENTS

In the fourth quarter of 2012, we identified that we had incorrectly reported UNS Electric's sales and purchase contracts, which did not result in the physical delivery of energy. The transactions were reported on a gross basis rather than on a net basis during the first three quarters of 2012 as well as the calendar years 2011 and 2010. This error resulted in an equal and offsetting overstatement of Electric Wholesale Sales and Purchased Energy in the income statements of $31 million in 2011 and $28 million in 2010. This error had no impact to operating income, net income, retained earnings, or cash flows. We assessed the impact of these errors on prior period financial statements and concluded they were not material to any period. However, the errors were significant to the individual line items. As a result, in accordance with Staff Accounting Bulletin 108, we have revised the 2011 and 2010 financial statements included herein to correct these errors. See Note 17 for the quarterly impact of the revisions on the years presented. The interim financial data is unaudited. The revisions noted above impacted UNS Energy's statements of income as shown in the tables below:

	UNS Energy			
	Year Ended December 31, 2011		Year Ended December 31, 2010	
	As Reported	As Revised	As Reported	As Revised
	-Thousands of Dollars-			
Income Statement				
Electric Wholesale Sales	$ 163,159	$ 132,346	$ 151,962	$ 123,943
Total Operating Revenues	1,509,515	1,478,702	1,453,966	1,425,947
Purchased Energy	307,423	276,610	307,288	279,269
Total Fuel and Purchased Energy	634,345	603,532	584,263	556,244
Total Operating Expenses	1,227,843	1,196,995	1,156,852	1,128,833

	UNS Energy 2012 Three Months Ended					
	March 31,		June 30,		September 30,	
	As Reported	As Revised	As Reported	As Revised	As Reported	As Revised
	-Thousands of Dollars					
Income Statement						
Electric Wholesale Sales	$ 37,104	$ 33,538	$ 28,684	$ 24,381	$ 32,494	$ 28,836
Purchased Energy	63,276	59,790	51,376	48,203	60,238	57,085
Total Fuel and Purchased Energy	134,276	130,790	151,328	148,155	175,687	172,534
Total Operating Expenses	284,479	280,984	299,112	295,932	330,852	327,700

	UNS Energy 2011 Three Months Ended							
	March 31,		June 30,		September 30,		December 31,	
	As Reported	As Revised	As Reported	As Revised	As Reported	As Revised	As Reported	As Revised
	-Thousands of Dollars							
Income Statement								
Electric Wholesale Sales	$ 40,914	$ 35,438	$ 38,744	$ 35,331	$ 41,847	$ 32,818	$ 41,654	$ 28,759
Purchased Energy	78,274	71,685	66,336	61,804	88,734	79,343	74,079	63,778
Total Fuel and Purchased Energy	146,579	139,990	155,539	151,007	182,766	173,376	149,461	139,159
Total Operating Expenses	299,946	293,357	298,383	293,852	327,187	317,796	302,327	291,990

	UNS Energy							
	Six Month Period Ended				Nine Month Period Ended			
	June 30, 2012		June 30, 2011		September 30, 2012		September 30, 2011	
	As Reported	As Revised	As Reported	As Revised	As Reported	As Revised	As Reported	As Revised
	-Thousands of Dollars							
Income Statement								
Electric Wholesale Sales	$ 65,787	$ 57,919	$ 79,658	$ 70,769	$ 98,282	$ 86,755	$ 121,506	$ 103,587
Total Operating Revenues	686,044	679,384	714,439	703,318	1,123,305	1,113,492	1,165,387	1,144,875
Purchased Energy	114,653	107,993	144,610	133,489	174,891	165,078	233,344	212,832
Total Fuel and Purchased Energy	285,605	278,945	302,118	290,997	461,292	451,479	484,885	464,373
Total Operating Expenses	583,590	576,916	598,330	587,209	914,428	904,616	925,518	905,005
Operating Income(1)	102,454	102,468	116,109	116,109	208,877	208,876	239,869	239,869

(1) Includes immaterial reclassifications from Operating Expense to Other Expense to conform with current year presentation.

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

The Financial Accounting Standards Board issued authoritative guidance that eliminated the option to report other comprehensive income in the statement of changes in equity. Rather, an entity must elect to present items of net income and other comprehensive income in one continuous statement or in two separate but consecutive statements. In 2012, we elected to include two separate but consecutive statements.

We implemented accounting guidance in 2012 which enhances our disclosures regarding unobservable inputs in calculating the fair market value of certain assets and liabilities. The guidance requires additional quantitative analysis of inputs when we use significant unobservable inputs to measure the fair value of our derivatives and financial instruments. See Note 11.

BASIS OF PRESENTATION

We consolidate our investments in subsidiaries when we hold a majority of the voting stock and we can exercise control over the operations and policies of the company. Consolidation means accounts of the parent and subsidiary are combined and intercompany balances and transactions are eliminated. Intercompany profits on transactions between regulated entities are not eliminated if recovery from ratepayers is probable. See Note 2.

USE OF ACCOUNTING ESTIMATES

Management makes estimates and assumptions when preparing financial statements under generally accepted accounting principles (GAAP) in the United States. These estimates and assumptions affect:

- Assets and liabilities on our balance sheets at the dates of the financial statements;
- Our disclosures about contingent assets and liabilities at the dates of the financial statements; and
- Our revenues and expenses in our income statements during the periods presented.

Because these estimates involve judgments based upon our evaluation of relevant facts and circumstances, actual results may differ from the estimates.

ACCOUNTING FOR RATE REGULATION

We generally use the same accounting policies and practices used by unregulated companies. However, sometimes GAAP requires that rate-regulated companies apply special accounting treatment to show the effect of rate regulation. For example, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in the rates charged to retail customers. Our Retail Rates are designed to allow TEP, UNS Gas, and UNS Electric an opportunity to recover reasonable operating and capital costs and earn a return on utility plant in service. Regulatory liabilities generally represent expected future costs that have already been collected from customers or items that are expected to be returned to customers through billing reductions. We evaluate regulatory assets each period and believe recovery is probable. If future recovery of costs ceases to be probable, the assets would be written off as a charge to current period earnings.

TEP, UNS Gas, and UNS Electric apply regulatory accounting as the following conditions exist:

- An independent regulator sets rates;
- The regulator sets the rates to recover the specific enterprise's costs of providing service; and
- Rates are set at levels that will recover the entity's costs and can be charged to and collected from customers.

CASH AND CASH EQUIVALENTS

We define Cash and Cash Equivalents as cash (unrestricted demand deposits) and all highly liquid investments purchased with an original maturity of three months or less.

As of December 31, 2012, we include $7 million of restricted cash in Investments and Other Property—Other on the balance sheets, of which $2 million has been legally restricted as to its use. At December 31, 2011, we included $9 million of restricted cash in Investments and Other Property – Other on the balance sheets, of which $3 million had been legally restricted as to its use.

UTILITY PLANT

Utility Plant includes the business property and equipment that supports electric and gas services, consisting primarily of generation, transmission, and distribution facilities. We report utility plant at original cost. Original cost includes materials and labor, contractor services, construction overhead (when applicable), and an Allowance for Funds Used During Construction (AFUDC).

We record the cost of repairs and maintenance, including planned major overhauls, to Operations and Maintenance (O&M) expense in the income statements as costs are incurred.

When a unit of regulated property is retired, we reduce accumulated depreciation by the original cost plus removal costs less any salvage value. There is no income statement impact.

AFUDC and Capitalized Interest

AFUDC reflects the cost of debt or equity funds used to finance construction and is capitalized as part of the cost of regulated utility plant. AFUDC amounts capitalized are included in rate base for establishing Retail Rates. For operations that do not apply regulatory accounting, we capitalize interest related only to debt as a cost of construction. The capitalized interest that relates to debt reduces Other Interest Expense in the income statements. The capitalized cost for equity funds is recorded as Other Income in the income statements.

The average AFUDC rates on regulated construction expenditures are included in the table below:

	2012	2011	2010
TEP	7.22%	6.72%	6.65%
UNS Gas	7.95%	8.32%	8.19%
UNS Electric	7.89%	8.18%	8.22%

UNS Energy did not capitalize interest in 2012. UNS Energy capitalized interest at a rate of 3.30% for 2011 and 1.96% for 2010.

Depreciation

We compute depreciation for owned utility plant on a group method straight-line basis at depreciation rates based on the economic lives of the assets. See Note 5. The Arizona Corporation Commission (ACC) approves depreciation rates for all generation and distribution assets. Transmission assets are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). Depreciation rates are based on average useful lives and reflect estimated removal costs, net of estimated salvage value for interim retirements. Below are the summarized average annual depreciation rates for all utility plant, which reflect immaterial adjustments in the calculation of rates in the years presented to exclude allocated depreciation (the adjustment did not affect Depreciation Expense recorded in the income statements).

	TEP	UNS Gas	UNS Electric
2012	3.22%	2.69%	3.99%
2011	3.14%	2.84%	4.02%
2010	3.16%	2.83%	4.35%

Computer Software Costs

We capitalize costs incurred to purchase and develop internal use computer software and amortize those costs over the estimated economic life of the product. If the software is no longer useful, we immediately charge capitalized computer software costs to expense.

TEP Utility Plant Under Capital Leases

TEP financed the following generation assets with capital leases: Springerville Unit 1; facilities at Springerville used in common with Springerville Unit 1 and Unit 2 (Springerville Common Facilities); and the Springerville Coal Handling Facilities. The capital lease expense incurred consists of Amortization Expense (see Note 5) and Interest Expense—Capital Leases. The lease terms are described in Note 6.

INVESTMENTS IN LEASE DEBT AND EQUITY

TEP held an investment in lease debt relating to Springerville Unit 1 through its maturity date in January 2013 and recorded this investment at amortized cost and recognized interest income. TEP holds a 14% equity interest in Springerville Unit 1 and a one-half interest in certain Springerville Common Facilities (Springerville Unit 1 Leases). The fair value of these investments is described in Note 11. These investments do not reduce the capital lease obligations reflected on the balance sheet because there is no legal right of offset. TEP makes lease payments to a trustee who then distributes the payments to the equity holders.

TEP accounts for its equity interest in the Springerville Unit 1 Lease trust using the equity method.

JOINTLY-OWNED FACILITIES

TEP has investments in several generation and transmission facilities jointly-owned with other companies. These projects are accounted for on a proportionate consolidation basis based on our ownership percentage. See Note 5.

ASSET RETIREMENT OBLIGATIONS

TEP and UNS Electric record a liability for the estimated present value of a conditional Asset Retirement Obligation (ARO) as follows:

- When it is able to reasonably estimate the fair value of any future obligation to retire as a result of an existing or enacted law, statute, ordinance, or contract; or
- If it can reasonably estimate the fair value.

When the liability is initially recorded at net present value, TEP and UNS Electric capitalize the cost by increasing the carrying amount of the related long-lived asset. TEP and UNS Electric adjust the liability to its present value by recognizing accretion expense in O&M expense, and the capitalized cost is depreciated in Depreciation and Amortization expense over the useful life of the related asset or when applicable, the terms of the lease subject to ARO requirements.

Based on the decommissioning studies to estimate timing and amount of future retirement of certain generation assets, both TEP and UNS Electric record legal AROs for these assets. Additionally, TEP and UNS Electric incurred AROs related to their photovoltaic assets as a result of entering into various ground leases.

TEP and UNS Electric record cost of removal for generation assets that are recoverable through the rates charged to retail customers. See Note 2.

We record cost of removal for transmission and distribution assets through depreciation rates and recover those amounts in the rates charged to retail customers. There are no legal obligations associated with transmission and distribution assets. We have recorded an obligation for estimated costs of removal as regulatory liabilities.

EVALUATION OF ASSETS FOR IMPAIRMENT

We evaluate long-lived assets and investments for impairment whenever events or circumstances indicate the carrying value of the assets may be impaired. If expected future cash flows (without discounting) are less than the carrying value of the asset, an impairment loss is recognized if the impairment is other-than-temporary and the loss is not recoverable through rates.

DEFERRED FINANCING COSTS

We defer the costs to issue debt and amortize such costs to interest expense on a straight-line basis over the life of the debt as this approximates the effective interest method. These costs include underwriters' commissions, discounts or premiums, and other costs such as legal, accounting, regulatory fees, and printing costs.

We defer and amortize the gains and losses on reacquired debt associated with regulated operations to interest expense over the remaining life of the original debt.

UTILITY OPERATING REVENUES

We record utility operating revenues when services or commodities are delivered to customers. Operating revenues include an estimate for unbilled revenues from service that has been provided but not billed by the end of an accounting period.

We determine amounts delivered through periodic readings of customer meters. At the end of the month, the usage since the last meter reading is estimated and the corresponding unbilled revenue is calculated. Unbilled revenue is estimated based on daily generation or purchased volumes, estimated usage by customer class, estimated line losses, and estimated average customer Retail Rates. Accrued unbilled revenues are reversed the following month when actual billings occur. The accuracy of the unbilled revenue estimate is affected by factors that include fluctuations in energy demands, weather, line losses, customer Retail Rates, and changes in the composition of customer classes.

The ACC authorized a rate-adjustment mechanism for TEP, UNS Gas, and UNS Electric that provides for the recovery of actual fuel, transmission, and purchased power/energy cost. The revenue surcharge or surcredit adjusts the customers' retail rate for delivered electricity or gas to collect or return under- or over-recovered energy costs. The ACC revises these rate-adjustment mechanisms periodically (annually for TEP and UNS Electric; monthly for UNS Gas) and may increase or decrease the costs recovered through Retail Rates for any difference between the total amount collected under the mechanisms and the recoverable costs incurred. See Note 2.

Arizona's mandatory Renewable Energy Standard (RES) requires TEP and UNS Electric to increase their use of renewable energy and allows recovery of compliance costs through a RES surcharge to customers. We charge customers a Demand Side Management (DSM) surcharge to recover the cost of ACC-approved Electric Energy Efficiency Programs (Electric EE Programs) or Gas Energy Efficiency Programs (Gas EE Programs). We defer differences between actual RES or DSM qualified costs incurred and the recovery of such costs from retail customers through the RES and DSM surcharges. Cost over-recoveries (the excess of cost recoveries through the RES and DSM surcharges over actual qualified costs incurred) are deferred as regulatory liabilities and cost under-recoveries (the excess of actual qualified costs incurred over cost recoveries through the RES and DSM surcharges) are deferred as regulatory assets. The surcharges typically reset annually and incorporate an adjustor mechanism that, upon approval of the ACC, allows us to apply any shortage or surplus in the prior year's program expenses to the subsequent year's RES or DSM surcharge. See Note 2.

For purchased power and wholesale sales contracts that are not settled with energy, TEP and UNS Electric net the sales contracts with the purchase power contracts and reflect the net amount as Electric Wholesale Sales. The corresponding cash receipts are recorded in the statement of cash flows as Cash Receipts from Electric Wholesale Sales, while cash payments are recorded as Purchased Energy/Power Costs Paid.

We record an Allowance for Doubtful Accounts to reduce accounts receivable for amounts estimated to be uncollectible. The allowance is determined based on historical bad debt patterns, retail sales, and economic conditions. We refer uncollected accounts to external collection agencies after 90 days.

TEP earns and recognizes Other Revenues monthly as the operator of Springerville Unit 3 on behalf of Tri-State and Springerville Unit 4 on behalf of SRP. Tri-State and SRP reimburse TEP for various operating expenses at Springerville, which are recorded in the respective line item of the income statements based on the nature of service or materials provided. Tri-State and SRP also pay TEP for the use of the Springerville Common Facilities and the Springerville Coal Handling Facilities which are recorded as Other Revenues.

INVENTORY

Materials and Supplies consist of transmission, distribution, and generation construction and repair materials. We record fuel, materials, and supply inventories at the lower of weighted average cost or market prices. We capitalize handling and procurement costs (such as materials, labor, overhead costs, and transportation costs) as part of the cost of the inventory.

RECOVERY OF FUEL AND PURCHASED ENERGY COSTS

TEP and UNS Electric Purchased Power and Fuel Adjustment Clause

TEP and UNS Electric record the actual fuel, transmission, and purchased power costs incurred on a monthly basis. Retail customers are billed monthly for the cost of fuel, transmission, and purchased power in Base Rates and via the current Purchased Power and Fuel Adjustment Clause (PPFAC) rate. The difference between the costs billed to customers (recoveries) and actual fuel costs incurred to provide retail electric service is deferred. Cost over-recoveries (excess of fuel cost recoveries) are deferred as regulatory liabilities and cost under-recoveries (excess of actual costs incurred over fuel costs recovered) are deferred as regulatory assets. See Note 2.

UNS Gas Purchased Gas Adjustor

UNS Gas defers the difference between actual gas costs incurred and the recovery of such costs under a Purchased Gas Adjustor (PGA) mechanism. Gas cost over-recoveries (the excess of gas costs recovered under the PGA mechanism over actual gas costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of actual gas costs incurred over gas costs recovered via the PGA mechanism) are deferred as regulatory assets. See Note 2.

RENEWABLE ENERGY CREDITS

The ACC uses Renewable Energy Credits (RECs) to measure compliance with the RES requirements. A REC equals one kWh generated from renewable resources. The cost of REC purchases are qualified renewable expenditures recoverable through the RES surcharge. When TEP or UNS Electric purchases renewable energy, the premium paid above the market cost of conventional power is the REC cost and the remaining cost is recoverable through the PPFAC.

When RECs are purchased, TEP and UNS Electric record the cost of the unretired RECs (an indefinite-lived intangible asset) as 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, TEP and UNS Electric recognize Purchased Power expense and Other Revenues in an equal amount, in the income statements. See Note 2.

INCOME TAXES

Due to the difference between GAAP and income tax laws, many transactions are treated differently for income tax purposes than for financial statement presentation purposes. Temporary differences are accounted for by recording deferred income tax assets and liabilities on our balance sheets. These assets and liabilities are recorded using income tax rates expected to be in effect when the deferred tax assets and liabilities are realized or settled. We reduce deferred tax assets by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or the entire deferred income tax asset will not be realized.

Tax benefits are recognized as reductions to Deferred Income Taxes – Noncurrent/Other Current Liabilities when it is more likely than not that a tax position will be sustained upon examination by the tax authorities based on the technical merits of the position. The tax benefit recorded is the largest amount that is more than 50% likely to be realized upon ultimate settlement with the tax authority, assuming full knowledge of the position and all relevant facts. Tax benefits taken on returns which do not meet these requirements are recorded in Deferred Income Taxes – Noncurrent/Other Liabilities – Noncurrent. Interest expense accruals relating to income tax obligations are recorded in Other Interest Expense.

Prior to 1990, TEP flowed through to ratepayers certain accelerated tax benefits related to utility plant as the benefits were recognized on tax returns. Regulatory Assets – Noncurrent includes income taxes recoverable through future rates, which reflects the future revenues due us from ratepayers as these tax benefits reverse. See Note 2.

We account for federal energy credits generated prior to 2012 using the grant accounting model. The credit is treated as deferred revenue, which is recognized over the depreciable life of the underlying asset. The deferred tax benefit of the credit is treated as a reduction to income tax expense in the year the credit arises. Federal energy credits generated in 2012 are deferred as Regulatory Liabilities – Noncurrent and amortized as a reduction in Income Tax Expense over the tax life of the underlying asset. Income Tax Expense attributable to the reduction in tax basis is accounted for in the year the federal energy credit is generated. All other federal and state income tax credits are treated as a reduction to Income Tax Expense in the year the credit arises.

Consolidated income tax liabilities are allocated to subsidiaries based on their taxable income as reported in the consolidated tax return.

TAXES OTHER THAN INCOME TAXES

We act as conduits or collection agents for sales taxes, utility taxes, franchise fees, and regulatory assessments. As we bill customers for these taxes and assessments, we record trade receivables. At the same time, we record liabilities payable, on the balance sheet, to governmental agencies for these taxes and assessments. These amounts are not reflected in the income statements.

DERIVATIVE FINANCIAL INSTRUMENTS

Risks and Overview

We are exposed to energy price risk associated with gas and purchased power requirements, volumetric risk associated with seasonal load, and operational risk associated with power plants, transmission, and transportation systems. We reduce our energy price risk through a variety of derivative and non-derivative instruments. The objectives for entering into such contracts include: creating price stability, ensuring we can meet load and reserve requirements, and reducing exposure to price volatility that may result from delayed recovery under the PPFAC or PGA. See Note 2.

We consider the effect of counterparty credit risk in determining the fair value of derivative instruments that are in a net asset position after incorporating collateral posted by counterparties and allocate the credit risk adjustment to individual contracts. We also consider the impact of our own credit risk after considering collateral posted on instruments that are in a net liability position and allocate the credit risk adjustment to all individual contracts.

We present cash collateral and derivative assets and liabilities associated with the same counterparty separately in our financial statements, and we separate all derivatives into current and long-term portions on the balance sheet.

In 2010 through 2012, we did not engage in trading of derivative financial instruments.

Cash Flow Hedges

TEP hedges the cash flow risk associated with unfavorable changes in the variable interest rates related to the leveraged lease arrangements relating to the Springerville Unit 1 Leases and variable rate industrial development revenue or pollution control revenue bonds (IDBs). In addition, TEP hedges the cash flow risk associated with a six-year power supply agreement using a six-year power purchase swap agreement. UNS Electric entered into a cash flow hedge in August 2011 to effectively convert the interest rate on the UNS Electric term loan from a variable rate to a fixed rate. TEP and UNS Electric account for cash flow hedges as follows:

- The effective portion of the changes in the fair value of the interest rate swaps and TEP's six-year power purchase swap agreement are recorded in Accumulated Other Comprehensive Income (AOCI) and the ineffective portion, if any, is recognized in earnings; and

- When TEP and UNS Electric determine a contract is no longer effective in offsetting the changes in cash flow of a hedged item, TEP and UNS Electric recognize the changes in fair value in earnings. The unrealized gains and losses at that time remain in AOCI and are reclassified into earnings as the underlying hedged transaction occurs.

We formally assess, both at the hedge's inception and on an ongoing basis, whether the derivatives have been and are expected to remain highly effective in offsetting changes in the cash flows of hedged items. We discontinue hedge accounting when: (1) the derivative is no longer effective in offsetting changes in the fair value or cash flows of a hedged item; (2) the derivative expires or is sold, terminated, or exercised; (3) it is no longer probable that the forecasted transaction will occur; or (4) we determine that designating the derivative as a hedging instrument is no longer appropriate.

Subsequent Measurement at Fair Value

- **TEP**

  TEP's hedges, such as forward power purchase contracts indexed to gas, short-term forward power sales contracts, or call and put options (gas collars), that did not qualify for either cash flow hedge accounting treatment or the normal scope exception are considered transactions subsequently measured at fair value. TEP hedges a portion of its monthly natural gas exposure for plant fuel, gas-indexed purchased power, and spot market purchases with fixed price contracts for a maximum of three years. Unrealized gains and losses are recorded as either a regulatory asset or regulatory liability to the extent they qualify for recovery through the PPFAC.

- **UNS Gas**

  UNS Gas enters into derivative contracts such as forward gas purchases and gas swaps, creating price stability and reducing exposure to natural gas price volatility that may result in delayed recovery under the PGA. Unrealized gains and losses are recorded as either a regulatory asset or regulatory liability, as the PGA mechanism permits the recovery of the cost of hedging contracts.

- **UNS Electric**

  UNS Electric hedges a portion of its purchased power exposure to fixed price and natural gas-indexed contracts with forward power purchases, financial gas swaps, and call and put options. Unrealized gains and losses are recorded as either a regulatory asset or regulatory liability, as the PPFAC mechanism allows recovery of the prudent costs of contracts for hedging fuel and purchased power costs.

Normal Purchases and Normal Sales

We enter into forward energy purchase and sales contracts, including call options, with counterparties for load serving requirements or counterparties with generating capacity to support our current load forecasts. These contracts are not required to be measured at fair value and are accounted for on an accrual basis. We evaluate our counterparties on an ongoing basis for non-performance risk to ensure it does not impact our ability to obtain the normal purchases and normal sales scope exception.

PENSION AND OTHER RETIREE BENEFITS

We sponsor noncontributory, defined benefit pension plans for substantially all employees and certain affiliate employees. Benefits are based on employees' years of service and average compensation. We also maintain a Supplemental Executive Retirement Plan (SERP) for upper management. TEP also provides limited health care and life insurance benefits for retirees. We fund the pension plans by contributing at least the minimum amount required under Internal Revenue Service (IRS) regulations.

We recognize the underfunded status of our defined benefit pension plans as a liability on our balance sheets. The underfunded status is measured as the difference between the fair value of the pension plans' assets and the projected benefit obligation for the pension plans. We recognize a regulatory asset to the extent these future costs are probable of recovery in the rates charged to retail customers, and expect to recover these costs over the estimated service lives of employees.

Additionally, we provide supplemental retirement benefits to certain employees whose benefits are subject to IRS benefit or compensation limitations. Changes in SERP benefit obligations are recognized as a component of AOCI.

Pension and other retiree benefit expense are determined by actuarial valuations, based on assumptions that we evaluate annually. See Note 9.

RECLASSIFICATIONS

UNS Energy and TEP reclassified the following items in the 2011 and 2010 financial statements to be comparable to the presentation in the 2012 financial statements:

- UNS Energy reclassified $4 million of 2011 trade receivables with credit balances from Accounts Receivable – Customer to Other Current Liabilities;
- UNS Energy and TEP reclassified $4 million of 2011 and 2010 O&M costs paid from Fuel Costs Paid to Payment of Operations and Maintenance Costs in the statements of cash flows;
- TEP reclassified $2 million of 2011 trade receivables with credit balances from Accounts Receivable – Customer to Other Current Liabilities;
- UNS Energy and TEP reclassified $1 million of 2011 payroll withholding taxes from Other Current Liabilities to Accrued Employee Expenses; and
- UNS Energy and TEP reclassified $35 thousand from Taxes Other Than Income Taxes to Other Expense in the 2011 income statement to conform to current year presentation.

NOTE 2. REGULATORY MATTERS

RATES AND REGULATION

The ACC and the FERC each regulate portions of the utility accounting practices and rates used by TEP, UNS Gas, and UNS Electric. The ACC regulates rates charged to retail customers, the siting of generation and transmission facilities, the issuance of securities, and transactions with affiliated parties. The FERC regulates terms and prices of transmission services and wholesale electricity sales.

TEP Rates

TEP 2008 Rate Order

The 2008 TEP Rate Order, issued by the ACC and effective December 1, 2008, provided an average base rate increase of 6% over TEP's previous Base Rates; an 8% authorized rate of return on Original Cost Rate Base (OCRB) of approximately $1 billion; a 5.6% rate of return on Fair Value Rate Base (FVRB) of approximately $1.5 billion, which did not include a return on the fair value increment of rate base (the fair value increment of rate base represents the difference between the OCRB and FVRB). The ACC authorized a fuel rate included in Base Rates of 2.9 cents per kilowatt-hour (kWh); a PPFAC effective January 1, 2009; and a base rate increase moratorium through January 1, 2013.

Pending TEP Rate Case

In July 2012, TEP filed a general rate case, on a cost-of-service basis, with the ACC requesting a Base Rate increase of approximately 15% to cover a revenue deficiency of $128 million. TEP requested a 7.74% return on an OCRB of $1.5 billion and a 5.68% return on FVRB of $2.3 billion. The return on FVRB includes a 1.56% return on the fair value increment of rate base (the fair value increment of rate base represents the difference between OCRB and FVRB of approximately $800 million).

TEP requested a Lost Fixed Cost Recovery (LFCR) mechanism to recover non-fuel costs that would go unrecovered due to lost kilowatt-hour (kWh) sales as a result of implementing the ACC's Electric Energy Efficiency Standards (Electric EE Standards) and the RES. TEP also requested a mechanism, which would be adjusted annually, to recover the costs of complying with environmental standards required by federal or other governmental agencies between rate cases.

TEP proposed a three-year pilot program allowing for investment in Electric EE Programs to meet the Electric EE Standards in the most cost effective manner. Under TEP's proposal, energy efficiency investments would be considered regulatory assets and amortized over a four-year period. TEP would earn a return on investment and recover the return and amortization expense through the existing DSM surcharge.

In February 2013, TEP, ACC Staff, and other parties to TEP's pending rate case proceeding entered into a proposed settlement agreement. The proposed settlement agreement requires the approval of the ACC before new rates can become effective.

UNS Gas Rates

2012 UNS Gas Rate Order

In April 2012, the ACC approved a Base Rate increase of $2.7 million, or 1.8%, and a mechanism to enable UNS Gas to recover lost fixed cost revenues as a result of implementing the ACC's Gas Energy Efficiency Standards (Gas EE Standards). UNS Gas recognized less than $0.1 million of revenue under the LFCR in 2012.

The ACC approved an authorized rate of return of 8.3% on an OCRB of $183 million, and a 1.0% return on the fair value increment of rate base (the fair value increment of rate base represents the difference between OCRB and FVRB of approximately $70 million). The new rates became effective in May 2012.

UNS Electric Rates

2010 UNS Electric Rate Order

In September 2010, the ACC approved a base rate increase of $7 million, or 4%, including an 8.3% authorized rate of return on an OCRB of $169 million, and a 1.3% return on the fair value increment of rate base (the fair value increment of rate base represents the difference between OCRB and FVRB of approximately $73 million). The order also authorized new depreciation rates, effective October 2010.

In July 2011, UNS Electric completed the ACC and the FERC approved purchase of BMGS from UED for $63 million, UED's book value for the assets. BMGS was included in UNS Electric's Rate Base through a revenue-neutral rate reclassification of approximately 0.7 cents per kWh from base power supply rate to non-fuel Base Rates.

Pending UNS Electric Rate Case

In December 2012, as required in the 2010 UNS Electric Rate Order, UNS Electric filed with the ACC a general rate case, on a cost-of-service basis, requesting a non-fuel Base Rate increase of $7.5 million, or 4.6%. UNS Electric requested a rate of return of 8.4% on an OCRB of approximately $217 million and a 6.7% rate of return on a FVRB of $286 million. The return on FVRB includes a 1.6% return on the fair value increment of rate base (the fair value increment of rate base represents the difference between OCRB and FVRB of approximately $69 million).

UNS Electric requested a LFCR mechanism to recover non-fuel costs that would go unrecovered due to lost kWh sales as a result of implementing Electric EE Standards and the RES. In addition to the LFCR mechanism, UNS Electric requested a Transmission Cost Adjustor (TCA). The TCA is designed to track changes to UNS Electric's FERC approved Open Access Transmission Tariff (OATT) rate which is updated annually and would allow UNS Electric to recover transmission costs in a timely manner.

COST RECOVERY MECHANISMS

TEP, UNS Gas, and UNS Electric have received regulatory decisions that allow for more timely recovery of certain costs through the recovery mechanisms described below.

Purchased Power and Fuel Adjustment Clause

The PPFAC provides for the adjustment of Retail Rates to reflect variations in retail fuel, transmission, and purchased power costs, including demand charges, and the prudent costs of contracts for hedging fuel. TEP and UNS Electric record deferrals for recovery or refund to the extent actual retail fuel, transmission, and purchased power costs vary from the fuel rate and current PPFAC rates. The TEP PPFAC became effective in January 2009. A PPFAC rate adjustment is made annually each April 1st (unless otherwise approved by the ACC) and goes into effect for the subsequent 12-month period automatically unless suspended by the ACC. UNS Electric's PPFAC rate adjustment is made annually each June 1st, effective for the subsequent 12-month period.

The PPFAC rate includes: 1) a forward component, under which TEP and UNS Electric recover or refund differences between, a) forecasted fuel, transmission, and purchased power costs for the upcoming calendar year and, b) those embedded in the fuel rate and the current PPFAC rates; and 2) a true-up component, which reconciles differences between actual fuel, transmission, and purchased power costs and those recovered through the combination of the fuel rate and the forward component for the preceding 12-month period.

The table below summarizes TEP's and UNS Electric's PPFAC rates in cents per kWh that are compared against actual fuel cost to create regulatory assets or liabilities:

	2012			2011		
	June - December	April - May	January - March	June - December	April - May	January - March
TEP						
PPFAC	0.77	0.77	0.53	0.53	0.53	0.09
CTC (1)	0.00	0.00	(0.53)	(0.53)	(0.53)	(0.09)
Total PPFAC Rate	0.77	0.77	—	—	—	—
UNS Electric	(1.44)	(0.88)	(0.88)	(0.88)	0.08	0.08

(1) Competition Transition Charge

As part of the TEP 2008 Rate Order, TEP was required to credit previously collected revenues to customers through the PPFAC. As a result, the PPFAC charge had been zero since it became effective in January 2009. In November 2011, the Fixed CTC revenue was fully refunded to customers and TEP began deferring the PPFAC eligible costs until a new PPFAC rate was approved by the ACC in April 2012.

UNS Gas Purchased Gas Adjustor

The PGA mechanism allows UNS Gas to adjust Retail Rates to reflect variations in natural gas costs. UNS Gas records deferrals for recovery or refund to the extent actual natural gas costs vary from the PGA rate. The PGA rate reflects a weighted, rolling average of the gas costs incurred by UNS Gas over the preceding 12 months. The PGA rate automatically adjusts monthly, but it is restricted from rising or falling more than $0.15 per therm in a twelve-month period. UNS Gas is required to request an additional surcredit if deferral balances reflect $10 million or more on a billed-to-customer basis. In 2012, the ACC approved a PGA temporary surcredit of 4.5 cents per therm effective for the period from May 2012 through April 2014, or when the PGA balance reaches zero, whichever comes first. At December 31, 2012, the PGA bank balance was over-collected by $10 million on a billed-to-customer basis, an increase of $2 million from December 31, 2011.

The PGA rate ranged from $0.5202 to $0.6501 cents per therm in 2012, and ranged from $0.6593 to $0.7296 cents per therm in 2011.

RES and Energy Efficiency Standards

The ACC has a mandatory RES that requires TEP and UNS Electric to expand their use of renewable energy through efforts funded by customer surcharges. TEP and UNS Electric are required to file five-year implementation plans with the ACC and annually seek approval for the upcoming year's RES funding amount. Similarly, TEP, UNS Gas, and UNS Electric recover the cost of ACC-approved energy efficiency programs through DSM surcharges established by the ACC.

The following table shows RES and DSM tariffs collected:

	TEP RES	UNS Electric RES	TEP DSM	UNS Gas DSM	UNS Electric DSM
	-Millions of Dollars-				
2012	$30	$7	$11	$1	$7
2011	35	7	11	1	2
2010	32	7	10	1	2

Renewable Energy Standard

The following table summarizes TEP's authorized 2010-2012 RES programs:

	Years Ended December 31,		
	2012[(2)]	2011	2010
	-Millions of Dollars-		
Investment in Company-Owned Solar Projects	$28	$28	$ 14
Return on Investment for Company-Owned Solar Projects	2	1	—
Program Budget[(1)]	30	36	44

(1) The authorized program budget for 2010 includes $12 million in carryforward of 2008 and 2009 RES funds.

(2) TEP met the 2012 renewable energy target of 3.5%.

The funding mechanism allows TEP to use RES funds to recover operating costs, depreciation, and property taxes, and to earn a return on company-owned solar projects until the projects can be incorporated in Base Rates.

In January 2013, the ACC approved TEP's 2013 RES implementation plan. Under the plan, TEP expects to collect approximately $36 million from retail customers during 2013. The plan includes an investment of $28 million in 2013 for company-owned solar projects, of which $8 million was previously approved by the ACC, as well as the continuation of the funding mechanism for company-owned solar projects. In accordance with the funding mechanism approved by the ACC, TEP could earn approximately $4 million pre-tax in 2013 on solar investments made in 2010, 2011, and 2012.

The following table summarizes UNS Electric's authorized 2010-2012 RES programs:

	Years Ended December 31,		
	2012[(1)]	2011	2010
	-Millions of Dollars-		
Investment in Company-Owned Solar Projects	$5	$ 5	$—
Return on Investment for Company-Owned Solar Projects	1	—	—
Program Budget	8	8	9

(1) UNS Electric met the 2012 renewable energy target of 3.5%.

UNS Electric will invest up to $5 million per year in company-owned renewable assets (between 2013 and 2014) subject to an annual prudency review and approval by the ACC. UNS Electric will recover the associated operating costs, depreciation, and property taxes under the RES program until the next rate case is filed and the assets are incorporated in the Base Rates.

In January 2013, the ACC approved UNS Electric's 2013 RES implementation plan. UNS Electric's will collect approximately $7 million from retail customers during 2013, a portion of which is expected to provide recovery of operating costs and a return on investment to UNS Electric for company-owned solar projects.

TEP and UNS Electric entered into multiple ACC-approved long-term purchase power agreements with companies developing renewable energy generation facilities. TEP and UNS Electric are required to purchase the full output of each facility for 20 years. Both utilities are authorized to recover a portion of the cost of renewable energy through the PPFAC, with the balance of costs recoverable through the RES tariff.

Energy Efficiency Standards

In 2010, the ACC approved new Electric EE Standards designed to require TEP and UNS Electric to implement cost-effective DSM programs, effective in 2011. In 2011, the Electric EE Standards targeted total retail kWh savings equal to 1.25% of 2010 sales, increasing to 22% by 2020, and provide for a DSM surcharge to recover the costs to implement DSM programs.

In May 2012, TEP filed a modification to its proposed 2011-2012 Energy Efficiency implementation plan with the ACC. The proposal included a request for a performance incentive for 2012 ranging from approximately $3 million to $4 million and the collection of the performance incentive over a period from October 1, 2012 to December 31, 2012. An administrative law judge issued a recommended opinion and order in August 2012. TEP did not record any income related to the proposed performance incentive in 2012. A proposed settlement agreement in TEP's pending rate case proceeding includes a new mechanism for recovery of costs incurred to implement DSM programs. The proposed settlement agreement requires the ACC's approval before it becomes effective.

The ACC approved new Gas EE Standards which required UNS Gas to implement cost effective DSM programs to reduce total retail therm sales in 2011, by 701,113 therms, or 0.5% of 2010 sales and to reduce total retail therm sales in 2012 by 1,679,890 therms, or 1.2% of 2011 sales. Targeted savings increase annually in subsequent years until they reach a cumulative annual reduction in retail therm sales of 6% by 2020.

In 2011, UNS Gas filed its 2011-2012 Gas Energy Efficiency implementation plan and subsequently filed an update in September 2011 which requested a waiver of the Gas EE Standards. In 2012, UNS Gas filed a request to amend its plan to include its 2013 Gas Energy Efficiency plan and for a modified waiver of the Gas EE Standards. We cannot predict when the ACC will rule on the Gas Energy Efficiency plan or the subsequent requests.

In January 2012, the ACC granted UNS Electric a waiver from complying with the 2011 and 2012 Electric EE Standards.

In June 2012, UNS Electric filed its 2013 Energy Efficiency implementation plan with the ACC. The proposal includes a request for a 2013 performance incentive of approximately $1 million. UNS Electric requested a waiver from complying with the 2013 Electric EE Standards. UNS Electric is unable to predict when the ACC will issue a final order in this matter.

Lost Fixed Cost Recovery Mechanism

In May 2012, the ACC authorized a mechanism for UNS Gas to recover therm sales lost as a result of implementing programs under the Gas EE Standards. The LFCR mechanism enables UNS Gas to recover non-purchased energy related costs that would go unrecovered due to lost therm sales as a result of implementing the Gas EE Standards. UNS Gas recorded less than $0.1 million of LFCR revenue in 2012.

Renewable Energy Credits

UNS Electric had $2 million of RECs on December 31, 2012, and $1 million of RECs on December 31, 2011, recorded in Other Assets on the balance sheets. TEP did not have RECs balances at the end of the periods presented since all RECs have been retired for compliance with the RES standard.

Regulatory Assets and Liabilities

The following tables summarize regulatory assets and liabilities:

	December 31, 2012			
	TEP	UNS Gas	UNS Electric	UNS Energy
	-Millions of Dollars-			
Regulatory Assets—Current				
Property Tax Deferrals (1)	$ 18	$—	$—	$ 18
Derivative Instruments (Notes 11 and 16)	2	3	6	11
PPFAC (3)	7	—	8	15
DSM (3)	5	—	—	5
Other Current Regulatory Assets (4)	2	1	—	3
Total Regulatory Assets—Current	34	4	14	52
Regulatory Assets—Noncurrent				
Pension and Other Retiree Benefits (Note 9)	130	4	5	139
Income Taxes Recoverable through Future Revenues (5)	8	—	2	10
PPFAC—Final Mine Reclamation and Retiree Health Care Costs (6)	22	—	—	22
Tucson to Nogales Transmission Line (7)	5	—	—	5
Other Regulatory Assets (4)	13	1	1	15
Total Regulatory Assets—Noncurrent	178	5	8	191
Regulatory Liabilities—Current				
PGA (8)	—	(17)	—	(17)
RES (8)	(19)	—	(4)	(23)
Other Current Regulatory Liabilities	(2)	(1)	(1)	(4)
Total Regulatory Liabilities—Current	(21)	(18)	(5)	(44)
Regulatory Liabilities—Noncurrent				
Net Cost of Removal for Interim Retirements (9)	(231)	(25)	(11)	(267)
Income Taxes Payable through Future Rates	(5)	(1)	—	(6)
Deferred Investment Tax Credit (10)	(5)	—	—	(5)
Other Regulatory Liabilities	—	—	(1)	(1)
Total Regulatory Liabilities—Noncurrent	(241)	(26)	(12)	(279)
Total Net Regulatory Assets (Liabilities)	$ (50)	$ (35)	$ 5	$ (80)

	December 31, 2011			
	TEP	UNS Gas	UNS Electric	UNS Energy
	-Millions of Dollars-			
Regulatory Assets—Current				
Property Tax Deferrals [1]	$ 16	$—	$—	$ 16
Derivative Instruments (Notes 11 and 16)	7	7	10	24
Deregulation Costs [2]	3	—	—	3
PPFAC [3]	34	—	7	41
DSM [3]	8	—	1	9
Other Current Regulatory Assets [4]	4	—	—	4
Total Regulatory Assets—Current	72	7	18	97
Regulatory Assets—Noncurrent				
Pension and Other Retiree Benefits (Note 9)	107	3	4	114
Income Taxes Recoverable through Future Revenues [5]	10	—	2	12
PPFAC [3]	6	—	—	6
PPFAC—Final Mine Reclamation and Retiree Health Care Costs [6]	20	—	—	20
Derivative Instruments (Notes 11 and 16)	2	2	3	7
Other Regulatory Assets [4]	12	1	1	14
Total Regulatory Assets—Noncurrent	157	6	10	173
Regulatory Liabilities—Current				
PGA [8]	—	(15)	—	(15)
RES [8]	(22)	—	(3)	(25)
Other Current Regulatory Liabilities	(2)	—	—	(2)
Total Regulatory Liabilities—Current	(24)	(15)	(3)	(42)
Regulatory Liabilities—Noncurrent				
Net Cost of Removal for Interim Retirements [9]	(198)	(23)	(10)	(231)
Other Regulatory Liabilities	(3)	(1)	—	(4)
Total Regulatory Liabilities—Noncurrent	(201)	(24)	(10)	(235)
Total Net Regulatory Assets (Liabilities)	$ 4	$ (26)	$ 15	$ (7)

Regulatory assets are either being collected in Retail Rates or are expected to be collected through Retail Rates in a future period. We describe regulatory assets and state when we earn a return below:

(1) Property Tax is recovered over an approximate six-month period as costs are paid, rather than as costs are accrued.

(2) Deregulation costs represent deferred expenses that TEP incurred to comply with various ACC deregulation orders, as authorized by the ACC. TEP earned a return on this asset and recovered these costs through Retail Rates over a four-year period ended November 2012.

(3) See Cost Recovery Mechanisms discussion above.

(4) TEP's other assets include unamortized loss on reacquired debt (recovery through 2032), coal contract amendment (recovery through 2017), and other assets (recovery through 2014). UNS Gas' other assets consist of rate case costs (recovery over 3 years), and costs of the low income assistance program.

(5) Income Taxes Recoverable through Future Revenues are amortized over the life of the assets.

(6) Final Mine Reclamation and Retiree Health Care Costs stem from TEP's jointly-owned facilities at the San Juan Generating Station, the Four Corners Generating Station, and the Navajo Generating Station. TEP is required to recognize the present value of its liability associated with final mine reclamation and retiree health care obligations. TEP recorded a regulatory asset because TEP is permitted to fully recover these costs through the PPFAC when the costs are invoiced by the miners. TEP expects to recover these costs over the remaining life of the mines, which is estimated to be between 14 and 20 years.

(7) The Tucson to Nogales Transmission Line regulatory asset does not earn a return. TEP and UNS Electric will request recovery from FERC for the prudent cost incurred to develop a high-voltage transmission line, which we expect to abandon. See Note 4.

Regulatory liabilities represent items that we either expects to pay to customers through billing reductions in future periods or plans to use for the purpose for which they were collected from customers, as described below:

(8) See Cost Recovery Mechanisms discussion above.

(9) Net Cost of Removal for Interim Retirements represents an estimate of the cost of future AROs net of salvage value. These are amounts collected through revenue for the net cost of removal of interim retirements for transmission, distribution, general, and intangible plant which are not yet expended. TEP and UNS Electric have also collected amounts for generation plant, which they have not yet expended.

(10) The Deferred Investment Tax Credit is related to federal energy credits generated in 2012 and are deferred as Regulatory Liabilities – Noncurrent and amortized over the tax life of the underlying asset.

Income Statement Impact of Applying Regulatory Accounting

Regulatory accounting had the following effects on TEP's net income:

	Years Ended December 31,		
	2012	2011	2010
	-Millions of Dollars-		
TEP			
Operating Revenues			
Amortization of the Fixed CTC Revenue to be Refunded	$ —	$ 36	$ 10
Operating Expenses			
Depreciation (related to Net Cost of Removal for Interim Retirements)	(33)	(29)	(30)
(Amortization)/Deferral of PPFAC Costs	(31)	6	22
Other	(7)	—	(8)
Non-Operating Income/Expenses			
Long-Term Debt (Amortization of Loss on Reacquired Debt Costs)	1	1	1
AFUDC—Equity	3	4	4
Income Taxes—Deferral	(3)	(8)	1
Offset by the Tax Effect of the Above Adjustments	26	(4)	—
Net (Decrease)/Increase to Net Income	$ (44)	$ 6	$—

Had UNS Gas and UNS Electric not applied regulatory accounting each would have recognized the difference between expected and actual purchased energy costs and commodity derivative unrealized gains or losses as a change in income statement expense, rather than as a change in regulatory balances. Regulatory accounting had the following effects on UNS Gas' and UNS Electric's net income:

	Years Ended December 31,		
	2012	2011	2010
	-Millions of Dollars-		
UNS Gas			
Net (Decrease)/Increase to Net Income	$(6)	$(5)	$(1)
UNS Electric			
Net (Decrease)/Increase to Net Income	(7)	3	(7)

Future Implications of Discontinuing Application of Regulatory Accounting

We regularly assess whether we can continue to apply regulatory accounting to regulated operations, and we have concluded regulatory accounting is applicable. If we stopped applying regulatory accounting to our regulated operations, the following would occur:

- Regulatory pension assets would be reflected in AOCI;
- We would write off remaining regulatory assets as an expense and regulatory liabilities as income in the income statements;
- At December 31, 2012, based on the regulatory assets balances, net of regulatory liabilities:
    - TEP would have recorded an extraordinary after-tax gain of $48 million and an after-tax loss in AOCI of $78 million;
    - UNS Gas would have recorded an extraordinary after-tax loss of $19 million and an after-tax loss in AOCI of $3 million; and
    - UNS Electric would have recorded an extraordinary after-tax gain of $6 million and an after-tax loss in AOCI of $3 million.

While future regulatory orders and market conditions may affect cash flows, our cash flows would not be affected if we stopped applying regulatory accounting to our regulated operations.

NOTE 3. SEGMENT AND RELATED INFORMATION

We have three reportable segments that are determined based on the way we organize our operations and evaluate performance:

(1) TEP, a regulated electric utility business, is our largest subsidiary;

(2) UNS Gas is a regulated gas distribution utility business; and

(3) UNS Electric is a regulated electric utility business.

Results for the UNS Energy and UES holding companies, Millennium, and UED are included in Other below.

We disclose selected financial data for our reportable segments in the following tables:

	Reportable Segments					
	TEP	UNS Gas	UNS Electric	Other	Reconciling Adjustments	UNS Energy
	-Millions of Dollars-					
2012						
Income Statement						
Operating Revenues-External	$1,145	$129	$189	$ —	$ (1)	$1,462
Operating Revenues-Intersegment	17	4	1	18	(40)	—
Depreciation and Amortization	150	9	18	—	—	177
Interest Income	—	—	—	1	—	1
Interest Expense	88	6	8	3	—	105
Income Tax Expense	39	6	11	—	—	56
Net Income	65	9	17	—	—	91
Cash Flow Statement						
Capital Expenditures	(253)	(16)	(38)	—	—	(307)
Balance Sheet						
Total Assets	3,461	310	370	1,121	(1,122)	4,140

	Reportable Segments					
	TEP	UNS Gas	UNS Electric	Other	Reconciling Adjustments	UNS Energy
	-Millions of Dollars-					
2011						
Income Statement						
Operating Revenues-External [(1)]	$1,141	$149	$188	$ —	$ 1	$1,479
Operating Revenues-Intersegment	15	2	2	23	(42)	—
Depreciation and Amortization	140	8	17	1	(1)	165
Interest Income	4	—	—	1	—	5
Interest Expense	89	7	7	9	—	112
Income Tax Expense (Benefit)	52	7	11	(1)	(2)	67
Net Income	85	10	18	—	(3)	110
Cash Flow Statement						
Capital Expenditures	(352)	(13)	(96)	(34)	121	(374)
Balance Sheet						
Total Assets	3,278	320	370	1,172	(1,151)	3,989
2010						
Income Statement						
Operating Revenue-External [(1)]	$1,096	$144	$185	$ —	$ 1	$1,426
Operating Revenue-Intersegment	29	6	2	28	(65)	—
Depreciation and Amortization	132	8	16	2	(2)	156
Interest Income	7	—	—	1	—	8
Interest Expense	88	7	7	9	—	111
Net Loss from Equity Method Investments	—	—	—	(6)	—	(6)
Income Tax Expense	60	6	10	4	(3)	77
Net Income (Loss)	108	9	15	(14)	(5)	113
Cash Flow Statement						
Capital Expenditures	(277)	(12)	(24)	(18)	—	(331)

(1) The amounts previously reported have been revised.

Reconciling adjustments consist of the elimination of intersegment revenue resulting from the following transactions, which are eliminated in consolidation:

	Reportable Segments			
	TEP	UNS Gas	UNS Electric	Other
Intersegment Revenue	-Millions of Dollars-			
2012:				
Wholesale Sales—TEP to UNS Electric [1]	$ 2	$—	$—	$—
Wholesale Sales—UNS Electric to TEP [1]	—	—	1	—
Wholesale Sales—UNS Gas to TEP [2]	—	1	—	—
Gas Revenue—UNS Gas to UNS Electric	—	3	—	—
Other Revenue—TEP to Affiliates[3]	12	—	—	—
Other Revenue—Millennium to TEP, UNS Electric, & UNS Gas [4]	—	—	—	18
Other Revenue—TEP to UNS Electric [5]	3	—	—	—
Total Intersegment Revenue	$ 17	$ 4	$ 1	$ 18
2011:				
Wholesale Sales—TEP to UNS Electric [1]	$ 2	$—	$—	$—
Wholesale Sales—UNS Electric to TEP [1]	—	—	2	—
Wholesale Sales—UED to UNS Electric	—	—	—	5
Gas Revenue—UNS Gas to UNS Electric	—	2	—	—
Other Revenue—TEP to Affiliates[3]	10	—	—	—
Other Revenue—Millennium to TEP, UNS Electric, & UNS Gas [4]	—	—	—	18
Other Revenue—TEP to UNS Electric [5]	3	—	—	—
Total Intersegment Revenue	$ 15	$ 2	$ 2	$ 23
2010:				
Wholesale Sales—TEP to UNS Electric [1]	$ 18	$—	$—	$—
Wholesale Sales—UNS Electric to TEP [1]	—	—	2	—
Wholesale Sales—UED to UNS Electric	—	—	—	11
Wholesale Sales—UNS Gas to TEP[2]	—	1	—	—
Gas Revenue—UNS Gas to UNS Electric	—	5	—	—
Other Revenue—TEP to Affiliates[3]	8	—	—	—
Other Revenue—Millennium to TEP, UNS Electric, & UNS Gas [4]	—	—	—	17
Other Revenue—TEP to UNS Electric[5]	3	—	—	—
Total Intersegment Revenue	$ 29	$ 6	$ 2	$ 28

(1) TEP and UNS Electric sell power to each other at third-party market prices.

(2) UNS Gas provides gas to TEP for generation of power at third-party market prices.

(3) Common costs (systems, facilities, etc.) are allocated on a cost-causative basis and recorded as revenue by TEP. Management believes this method of allocation is reasonable.

(4) Millennium provides a supplemental workforce and meter-reading services to TEP, UNS Gas, and UNS Electric. Amounts are based on costs of services performed and management believes that the charges for services are reasonable. Millennium charged TEP $17 million in 2012 and 2011, and $16 million in 2010 for these services.

(5) TEP charged UNS Electric for control area services based on a FERC-approved tariff.

TEP provides all corporate services (finance, accounting, tax, information technology services, etc.) to UNS Energy affiliated entities. Costs are directly assigned to the benefiting entity. Direct costs charged by TEP to affiliates were $10 million in 2012, 2011, and 2010.

UNS Energy incurs corporate costs that are allocated to TEP and its other subsidiaries. Corporate costs are allocated based on a weighted-average of three factors: assets, payroll, and revenues. Management believes this method of allocation is reasonable and approximates the cost that TEP would have incurred as a standalone entity. Charges allocated to TEP were $2 million in 2012 and 2011, and $3 million in 2010.

Other

Other significant reconciling adjustments include the elimination of investments in subsidiaries held by UNS Energy and reclassifications of deferred tax assets and liabilities.

NOTE 4. COMMITMENTS, CONTINGENCIES, AND ENVIRONMENTAL MATTERS

TEP COMMITMENTS

Firm Purchase Commitments

At December 31, 2012, TEP had the following firm non-cancelable purchase commitments (minimum purchase obligations) and operating leases:

	Purchase Commitments						
	2013	2014	2015	2016	2017	Thereafter	Total
	-Millions of Dollars-						
Fuel (Including Transportation)	$ 65	$ 65	$ 50	$ 47	$ 39	$ 60	$ 326
Purchased Power	50	41	29	28	28	386	562
RES Performance-Based Incentive Payments	4	4	4	4	4	42	62
Solar Equipment	12	—	—	—	—	—	12
Transmission	3	3	3	3	3	22	37
Operating Leases	2	2	2	1	1	10	18
Service Agreement	2	2	—	—	—	—	4
Total Unrecognized Firm Commitments	$138	$117	$ 88	$ 83	$ 75	$520	$1,021

Fuel, Purchased Power, and Transmission Contracts

TEP has long-term contracts for the purchase and delivery of coal with various expiration dates through 2020. Amounts paid under these contracts depend on actual quantities purchased and delivered. Some of these contracts include a price adjustment clause that will affect the future cost. TEP expects to spend more than the minimum purchase obligations to meet its fuel requirements.

TEP has agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. In general, these contracts provide for capacity payments and energy payments based on actual power taken under the contracts. These contracts expire in various years between 2013 and 2015. Certain of these contracts are at a fixed price per MW and others are indexed to natural gas prices. The commitment amounts included in the table are based on projected market prices as of December 31, 2012.

Additionally, Purchased Power includes six 20-year Power Purchase Agreements (PPAs) with renewable energy generation facilities that achieved commercial operation in 2011 and 2012. TEP is obligated to purchase 100% of the output from these facilities. TEP has additional long-term renewable PPAs to comply with the RES requirements; however, TEP's obligation to purchase power under these agreements does not begin until the facilities are operational.

Fuel, purchased power, and transmission costs are recoverable from customers through the PPFAC. A portion of the cost of renewable energy is recoverable through the PPFAC, with the balance of costs recoverable through the RES tariff. See Note 2.

RES Performance-Based Incentives

TEP has entered into REC purchase agreements to purchase the environmental attributes from retail customers with solar installations. Payments for the RECs are termed Performance-Based Incentives (PBIs) and are paid in contractually agreed-upon intervals (usually quarterly) based on metered renewable energy production. PBIs are recoverable through the RES tariff. See Note 2.

Solar Equipment

TEP committed to purchase 9 MW of photovoltaic equipment through December 2013. TEP spent $11 million in 2012 and $10 million in 2011 under this contract. The ACC approved this purchase under TEP's RES implementation plan. TEP earns a return on investment in company-owned solar projects. See Note 2.

Operating Leases

TEP's aggregate operating lease expense is primarily for rail cars, office facilities, and computer equipment, with varying terms, provisions, and expiration dates. This expense totaled $2 million in each of 2012, 2011, and 2010.

Service Agreement

In February 2012, TEP entered into a long-term agreement for information technology services. TEP is obligated to pay $2 million per year through December 2014.

UNS GAS AND UNS ELECTRIC COMMITMENTS

At December 31, 2012, UNS Gas had firm non-cancelable purchase commitments for fuel, including transportation, as described in the table below:

	Purchase Commitments						
	2013	2014	2015	2016	2017	Thereafter	Total
	-Millions of Dollars-						
Total Unrecognized Firm Commitments – Fuel	$26	$13	$8	$6	$4	$17	$74

UNS Gas purchases gas from various suppliers at market prices. However, UNS Gas' risk of loss due to increased costs (as a result of changes in market prices of fuel) is mitigated through the use of the PGA, which provides for the pass-through of actual commodity costs to customers. UNS Gas' forward gas purchase agreements expire through 2015. Certain of these contracts are at a fixed price per Million British Thermal Units (MMBtu) and others are indexed to natural gas prices. The commitment amounts included in the table above are based on market prices as of December 31, 2012. UNS Gas has firm transportation agreements with capacity sufficient to meet its load requirements. These contracts expire in various years between 2013 and 2024.

At December 31, 2012, UNS Electric had various firm non-cancelable purchase commitments as described in the table below:

	Purchase Commitments						
	2013	2014	2015	2016	2017	Thereafter	Total
	-Millions of Dollars-						
Purchased Power	$55	$50	$14	$6	$ 5	$ 80	$210
Transmission	4	2	2	1	—	—	9
Total Unrecognized Firm Commitments	$59	$52	$16	$7	$ 5	$ 80	$219

UNS Electric enters into agreements with various energy suppliers for purchased power at market prices to meet its energy requirements. In general, these contracts provide for capacity payments and energy payments based on actual power taken. These contracts expire in various years through 2015. Certain of these contracts are at a fixed price per MW and others are indexed to natural gas prices. The commitment amounts included in the table above are based on market prices as of December 31, 2012. Purchased power commitments also include two 20-year PPAs with renewable energy generation facilities that achieved commercial operation in 2011 and 2012. UNS Electric is obligated to purchase 100% of the output from these facilities.

UNS Electric imports the power it purchases over the Western Area Power Administration's (WAPA) transmission lines. UNS Electric's transmission capacity agreements with WAPA provide for annual rate adjustments and expire in 2013 and 2016. However, the effects of both purchased power and transmission cost adjustments are mitigated through UNS Electric's PPFAC.

UNS Gas and UNS Electric have operating leases, primarily for office facilities and computer equipment, with varying terms and expiration dates. The expense was less than $1 million in each of the years 2012, 2011, and 2010. UNS Gas' and UNS Electric's estimated future minimum payments under non-cancelable operating leases are less than $1 million per year for 2013 through 2031.

RES Performance-Based Incentives

UNS Electric is contractually obligated to make RES PBI payments to retail customers with solar installations. UNS Electric's total obligation for RES PBIs is about $6 million with payments required over periods ranging from 10 to 20 years based on metered renewable energy production. PBIs are recoverable through the RES tariff. See Note 2.

Solar Project

In December 2012, UNS Electric entered into an agreement for the construction of a 7.182 MW solar photovoltaic power plant that will be constructed in two phases. The first phase will result in a 4.2 MW plant that UNS Electric expects to be operational in June of 2013. The balance of the project will be completed in 2014. UNS Electric invested $5 million in this project in 2012. The contract requires additional investments of $4 million in each of 2013 and 2014. This is an approved project under UNS Electric's RES implementation plan. See Note 2.

TEP CONTINGENCIES

Springerville Generating Station Unit 3 Outage

In July 2012, Springerville Unit 3 experienced an unplanned outage. As a result of the outage, TEP recorded a pre-tax loss of $2 million in the third quarter of 2012 as TEP did not meet certain availability requirements under the terms of TEP's operating agreement with Tri-State.

Claims Related to San Juan Generating Station

San Juan Coal Company (SJCC) operates an underground coal mine in an area where certain gas producers have oil and gas leases with the federal government, the State of New Mexico, and private parties. These gas producers allege that SJCC's underground coal mine interferes with their operations, reducing the amount of natural gas they can recover. SJCC has compensated certain gas producers for any remaining production from wells deemed close enough to the mine to warrant plugging and abandoning them. These settlements, however, do not resolve all potential claims by gas producers in the area. TEP owns 50% of Units 1 and 2 at San Juan Generating Station (San Juan), which represents approximately 20% of the total generation capacity at San Juan, and is responsible for its share of any settlements. TEP cannot estimate the impact of any future claims by these gas producers on the cost of coal at San Juan.

Claims Related to Four Corners Generating Station

In October 2011, EarthJustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New Mexico against Arizona Public Service Company (APS) and the other Four Corners Generating Station (Four Corners) participants, alleging violations of the Prevention of Significant Deterioration (PSD) provisions of the Clean Air Act at Four Corners. In January 2012, EarthJustice amended their complaint alleging violations of New Source Performance Standards resulting from equipment replacements at Four Corners. Among other things, the plaintiffs seek to have the court issue an order to cease operations at Four Corners until any required PSD permits are issued, and order the payment of civil penalties, including a beneficial mitigation project. In April 2012, APS filed Motions to Dismiss with the court for all claims asserted by EarthJustice in the amended complaint. The parties filed a Joint Motion to Stay in November 2012 in furtherance of settlement talks.

TEP owns 7% of Four Corners Units 4 and 5 and is liable for its share of any resulting liabilities. TEP cannot predict the final outcome of the claims relating to Four Corners, and, due to the general and non-specific nature of the claims and the indeterminate scope and nature of the injunctive relief sought for these claims, TEP cannot determine estimates of the range of loss at this time. TEP accrued estimated losses of less than $1 million in 2011 for this claim.

Mine Closure Reclamation at Generating Stations Not Operated by TEP

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which TEP has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing Navajo Generating Station (Navajo), San Juan, and Four Corners. TEP’s share of reclamation costs is expected to be $27 million upon expiration of the coal supply agreements, which expire between 2016 and 2019. The reclamation liability (present value of future liability) was $16 million at December 31, 2012, and $13 million at December 31, 2011.

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 credit-adjusted risk-free interest rate to be used to discount future liabilities. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreement terms. TEP does not believe that recognition of its final reclamation obligations will be material to TEP in any single year because recognition will occur over the remaining terms of its coal supply agreements.

TEP’s PPFAC allows us to pass through most fuel costs (including final reclamation costs) to customers. Therefore, TEP classifies these costs as a regulatory asset by increasing the regulatory asset and the reclamation liability over the remaining life of the coal supply agreements on an accrual basis and recovering the regulatory asset through the PPFAC as final mine reclamation costs are paid to the coal suppliers.

In June 2012, the participants at San Juan executed a Trust Reclamation Agreement requiring each participant to individually establish and fund a trust based on the participant’s share of the estimated final mine reclamation costs. The trust must remain in effect through completion of final mine reclamation activities currently projected to be 2050. TEP established and funded its trust with $1 million in 2012. TEP expects to make additional cumulative deposits to the trust of approximately $1 million over the next five years.

Tucson to Nogales Transmission Line

TEP and UNS Electric are parties to a project development agreement for the joint construction of a 60-mile transmission line from Tucson, Arizona to Nogales, Arizona. This project was initiated in response to an order by the ACC to UNS Electric to improve the reliability of electric service in Nogales. TEP had previously capitalized $11 million related to the project, including $2 million to secure land and land rights. UNS Electric had previously capitalized $0.4 million related to the project.

TEP and UNS Electric expect to abandon the project based on the cost of the proposed 345-kV line, the difficulty in reaching agreement with the Forest Service on a path for the line, and concurrence by the ACC of recent transmission plans filed by TEP and UNS Electric supporting the elimination of this project. In TEP’s pending rate case proceeding before the ACC, TEP entered into a proposed settlement agreement in which it agrees to seek recovery of the project costs from FERC before seeking rate recovery from the ACC. In the fourth quarter of 2012, TEP and UNS Electric wrote off a portion of the capitalized costs believed not probable of recovery and recorded a regulatory asset for the balance deemed probable of recovery. TEP and UNS Electric believe it is probable that we will recover at least $5 million and $0.2 million, respectively, of costs incurred through 2012.

RESOLUTION OF CONTINGENCIES

In April 2010, the Sierra Club filed a citizens’ suit under the Resource Conservation and Recovery Act (RCRA) and the Surface Mine Control and Reclamation Act (SMCRA) in the United States District Court for the District of New Mexico against Public Service Company of New Mexico (PNM), as operator of San Juan, SJCC, and PNM’s and SJCC’s respective parent companies. The suit alleged that certain activities at San Juan and the San Juan mine associated with the treatment, storage, and disposal of coal and Coal Combustion Residuals (CCRs) violated

RCRA and SMCRA. The suit sought an injunction with respect to the placement of CCRs at the mine, the imposition of civil penalties, and attorney's fees and costs. In March 2012, the parties settled the case. The settlement was approved by the court.

TEP is responsible for its share of the settlement of the San Juan claims. TEP recorded less than $1 million for its share of the costs to fund environmental projects and Sierra Club attorney and expert fees required by the settlement, substantially all of which was recorded in 2011. In addition, TEP paid $1 million for its share of construction costs for a new groundwater recovery system adjacent to San Juan and other environmental projects required by the settlement.

San Juan Mine Fire

In September 2011, a fire at the underground mine that provides coal to San Juan caused mining operations to shut down. The mine resumed production in June 2012. The mine fire did not have a material effect on TEP's financial condition, results of operations, or cash flows due to the use of on-hand inventory of previously mined coal and the low market price of wholesale power during the closure. TEP awaits final resolution in the matter pending an insurance settlement between the mine operator and its insurance company.

ENVIRONMENTAL MATTERS

Environmental Regulation

The Environmental Protection Agency (EPA) limits the amount of sulfur dioxide (SO_2), nitrogen oxide (NOx), particulate matter, mercury and other emissions released into the atmosphere by power plants. TEP capitalized $2 million in 2012, $8 million in 2011, and $18 million in 2010 in construction costs to comply with environmental requirements, including TEP's share of new pollution control equipment installed at San Juan. TEP expects to capitalize environmental compliance costs of $10 million in 2013 and $27 million in 2014. In addition, TEP recorded O&M expenses of $15 million in 2012, $12 million in 2011, and $14 million in 2010 related to environmental compliance. TEP expects environmental O&M expenses to be $16 million in 2013.

TEP may incur additional costs to comply with future changes in federal and state environmental laws, regulations, and permit requirements at its power plants. Complying with these changes may reduce operating efficiency. TEP expects to recover the cost of environmental compliance from its ratepayers.

Hazardous Air Pollutant Requirements

The Clean Air Act requires the EPA to develop emission limit standards for hazardous air pollutants that reflect the maximum achievable control technology. In February 2012, the EPA issued final rules called the Mercury and Air Toxics Standards setting limits for mercury emissions and other hazardous air pollutants from power plants.

Navajo

Based on the EPA's final standards, Navajo may need mercury and particulate matter emission control equipment by 2015. TEP's share of the estimated capital cost of this equipment is less than $1 million for mercury control and about $43 million if the installation of baghouses to control particulates is necessary. TEP expects its share of the annual operating costs for mercury control and baghouses to be less than $1 million each. The operator of Navajo is currently analyzing the need for baghouses under various regulatory scenarios, which include the regional haze final Best Available Retrofit Technology (BART) rules.

San Juan

TEP expects San Juan's current emission controls to be adequate to comply with the EPA's final standards.

Four Corners

Based on the EPA's final standards, Four Corners may need mercury emission control equipment by 2015. The estimated capital cost of this equipment is less than $1 million. TEP expects the annual operating cost of the mercury emission control equipment to be less than $1 million.

Springerville

Based on the EPA's final standards, Springerville may need mercury emission control equipment by 2015. The estimated capital cost of this equipment for Springerville Units 1 and 2 is about $5 million. TEP expects the annual operating cost of the mercury emission control equipment to be about $3 million.

Sundt Generating Station

TEP expects the final EPA standards will have little effect on capital expenditures at Sundt Generating Station (Sundt).

Regional Haze Rules

The EPA's regional haze rules require emission controls known as BART for certain industrial facilities emitting air pollutants that reduce visibility. The rules call for all states to establish goals and emission reduction strategies for improving visibility in national parks and wilderness areas. States must submit these goals and strategies to the EPA for approval. Because Navajo and Four Corners are located on the Navajo Indian Reservation, they are not subject to state oversight. The EPA oversees regional haze planning for these power plants.

Complying with the EPA's BART findings, and with other environmental rules, may make it economically impractical to continue operating the Navajo, San Juan, and Four Corners power plants or for individual owners to continue to participate in these power plants. TEP cannot predict the ultimate outcome of these matters.

Navajo

In January 2013, the EPA proposed an alternative BART determination that would require the installation of SCR technology on all three units at Navajo by 2023. If SCR technology is ultimately required at Navajo, TEP estimates its share of the capital cost will be $42 million. Also, the installation of SCR technology at Navajo could increase the power plant's particulate emissions which may require that baghouses be installed. TEP estimates that its share of the capital expenditure for baghouses would be about $43 million. TEP's share of annual operating costs is estimated at less than $1 million for each of the control technologies (SCR and baghouses).

San Juan

In August 2011, the EPA issued a Federal Implementation Plan (FIP) establishing new emission limits for air pollutants at San Juan. These requirements are more stringent than those proposed by the State of New Mexico. The FIP requires the installation of SCR technology with sorbent injection on all four units within five years to reduce NOx and control sulfuric acid emissions by September 2016. TEP estimates its share of the cost to install SCR technology with sorbent injection to be between $180 million and $200 million. TEP expects its share of the annual operating costs for SCR technology to be approximately $6 million.

In 2011, PNM filed a petition for review of and a motion to stay the FIP with the Tenth Circuit United States Court of Appeals (Circuit Court). In addition, PNM filed a request for reconsideration of the rule with the EPA and a request to stay the effectiveness of the rule pending the EPA's reconsideration and the review by the Circuit Court. The State of New Mexico filed similar motions with the Circuit Court and the EPA. Several environmental groups were granted permission to join in opposition to PNM's petition to review in the Circuit Court. In addition, WildEarth Guardians filed a separate appeal against the EPA challenging the FIP's five-year implementation schedule. PNM was granted permission to join in opposition to that appeal. In March 2012, the Circuit Court denied PNM's and the State of New Mexico's motion for stay. Oral argument on the appeal was heard in October 2012 and the parties are currently awaiting the Circuit Court's decision.

In February 2013, the State of New Mexico released a proposed plan that it presented to the EPA as an alternative to the FIP. The proposed plan includes: the retirement of San Juan Units 2 and 3 by December 31, 2017; the replacement of those units with non-coal generation sources; and the installation of selective non-catalytic reduction technology (SNCR) on San Juan Units 1 and 4 by January 2016. TEP estimates its share of the cost to install SNCR technology on San Juan Unit 1 would be approximately $25 million.

TEP owns 340 MW, or 50%, of San Juan Units 1 and 2. At December 31, 2012, the book value of TEP's share of San Juan Units 1 and 2 was $217 million. If Unit 2 is retired early, we expect to request ACC approval to recover, over a reasonable time period, all costs associated with the early closure of the unit. We are evaluating various replacement resources. Any decision regarding early closure and replacement resources will require various actions by third parties as well as UNS Energy board and regulatory approvals.

If the proposed plan is not accepted and agreed to by the EPA, the New Mexico Environmental Department, the San Juan participants, and various other regulatory entities, TEP may begin making capital expenditures to install SCRs on San Juan Units 1 and 2 in 2013 to meet the FIP compliance deadline. TEP cannot predict the ultimate outcome of this matter.

Four Corners

In August 2012, the EPA finalized the regional haze FIP for Four Corners. The final FIP requires SCR technology to be installed on all five units by 2017. However, the FIP also includes an alternative plan that allows APS to close their wholly-owned Units 1, 2, and 3 and install SCR technology on Units 4 and 5. This option allows the installation of SCR technology to be delayed until July 2018. In either case, TEP's estimated share of the capital costs to install SCR technology is about $35 million. TEP's share of annual operating costs for SCR is estimated at $2 million.

Springerville

Regional haze regulations requiring emission control upgrades do not apply to Springerville currently and are not likely to impact Springerville operations until after 2018.

Sundt

In December 2012, the EPA issued a proposed rule on provisions, that had not been previously addressed, in the Arizona State Implementation Plan related to regional haze. Contrary to the Arizona plan the EPA disapproved, among other things, the determination that Sundt Unit 4 is not subject to the BART provisions of the regional haze rule and is therefore subject to BART requirements. If the BART eligibility determination stands, Sundt Unit 4 will be required to reduce certain emissions within five years of the final EPA BART rule which is likely to be completed in October 2013. The EPA is expected to release a proposed BART requirement for Sundt Unit 4 in March 2013.

NOTE 5. UTILITY PLANT AND JOINTLY-OWNED FACILITIES

UTILITY PLANT

The following table shows Utility Plant in Service by major class:

	UNS Energy		TEP	
	December 31,		December 31,	
	2012	2011	2012	2011
	-Millions of Dollars-			
Plant in Service:				
Electric Generation Plant	$1,932	$1,879	$1,847	$1,795
Electric Transmission Plant	842	810	796	766
Electric Distribution Plant	1,495	1,453	1,271	1,234
Gas Distribution Plant	240	233	—	—
Gas Transmission Plant	18	18	—	—
General Plant	347	331	309	302
Intangible Plant—Software Costs [1] [2]	124	122	123	121
Intangible Plant—Other	5	5	—	—
Electric Plant Held for Future Use	3	5	2	4
Total Plant in Service	$5,006	$4,856	$4,348	$4,222
Utility Plant under Capital Leases	$ 583	$ 583	$ 583	$ 583

[1] Unamortized computer software costs were $36 million for UNS Energy and $35 million for TEP as of December 31, 2012, and $43 million for UNS Energy and $42 million for TEP as of December 31, 2011.

[2] The amortization of computer software costs in UNS Energy's income statements was $13 million in 2012, $10 million in 2011, and $9 million in 2010. The amortization of computer software costs in TEP's income statements before intercompany allocations was $13 million in 2012, $10 million in 2011, and $9 million in 2010.

TEP Utility Plant under Capital Leases

All TEP utility plant under capital leases is used in TEP's generation operations and amortized over the primary lease term. See Note 6. At December 31, 2012, the utility plant under capital leases includes: 1) Springerville Unit 1; 2) Springerville Common Facilities; and 3) Springerville Coal Handling Facilities. The following table shows the amount of lease expense incurred for TEP's generation-related capital leases:

	Years Ended December 31,		
	2012	2011	2010
	-Millions of Dollars-		
Lease Expense:			
Interest Expense – Included in:			
Capital Leases	$ 34	$40	$47
Operating Expenses – Fuel	3	4	4
Other Expense	—	1	2
Amortization of Capital Lease Assets – Included in:			
Operating Expenses – Fuel	4	3	3
Operating Expenses – Amortization	14	14	14
Total Lease Expense	$ 55	$62	$70

The depreciable lives as of December 31, 2012, were as follows:

Major Class of Utility Plant in Service	**TEP**	**UNS Gas and UNS Electric**
Electric Generation Plant	11-57 years	38-49 years
Electric Transmission Plant	20-60 years	20-50 years
Electric Distribution Plant	28-60 years	23-50 years
Gas Distribution Plant	n/a	30-55 years
Gas Transmission Plant	n/a	30-65 years
General Plant	5-31 years	5-40 years
Intangible Plant	3-19 years	3-32 years

See *Utility Plant* in Note 1 and *TEP Capital Lease Obligations* in Note 6.

JOINTLY-OWNED FACILITIES

At December 31, 2012, TEP's interests in jointly-owned generating stations and transmission systems were as follows:

	Ownership Percentage	**Plant in Service**	**Construction Work in Progress**	**Accumulated Depreciation**	**Net Book Value**
		-Millions of Dollars-			
San Juan Units 1 and 2	50.0%	$ 443	$ 7	$220	$230
Navajo Units 1, 2, and 3	7.5	148	1	106	43
Four Corners Units 4 and 5	7.0	97	2	73	26
Luna Energy Facility	33.3	53	—	—	53
Transmission Facilities	7.5 to 95.0	328	22	186	164
Total		$1,069	$ 32	$585	$516

TEP has financed or provided funds for the above facilities and TEP's share of its operating expenses is reflected in the income statements based on the nature of the expense.

ASSET RETIREMENT OBLIGATIONS

The accrual of AROs is primarily related to generation and photovoltaic assets and is included in Deferred Credits and Other Liabilities on the balance sheets. The following table reconciles the beginning and ending aggregate carrying amounts of ARO accruals on the balance sheets:

	UNS Energy and TEP	
	December 31, 2012	**2011**
	-Millions of Dollars-	
Beginning Balance	$ 13	$ 4
Liabilities Incurred	—	1
Liabilities Settled	—	—
Accretion Expense	1	—
Revision to Estimated Cash Flows	—	8
Ending Balance	$ 14	$ 13

NOTE 6. DEBT, CREDIT FACILITIES, AND CAPITAL LEASE OBLIGATIONS

Long-term debt matures more than one year from the date of the financial statements. We summarize UNS Energy's and TEP's long-term debt in the statements of capitalization.

UNS ENERGY DEBT—CONVERTIBLE SENIOR NOTES

In 2005, UNS Energy issued $150 million of 4.50% Convertible Senior Notes (Convertible Senior Notes) due in 2035. In 2012, UNS Energy converted or redeemed the entire $150 million Convertible Senior Notes outstanding. Holders of the Convertible Senior Notes had the option of converting their interests to Common Stock at a conversion rate applicable at the time of each notice of redemption or receiving the redemption price of par plus accrued interest for the Convertible Senior Notes. In the first quarter of 2012, holders of approximately $73 million of the Convertible Senior Notes converted their interests into approximately 2.1 million shares of Common Stock and $2 million were redeemed for cash. In the second quarter of 2012, holders of approximately $74 million of Convertible Senior Notes converted their interests into approximately 2.2 million shares of Common Stock and $1 million were redeemed for cash.

TEP DEBT

Tax-Exempt Variable Rate Bonds and Interest Rate Swap

TEP had $215 million in tax-exempt variable rate debt outstanding at December 31, 2012 and December 31, 2011. Each series of bonds is supported by a Letter of Credit (LOC) issued under the TEP Credit Agreement or separate TEP Letter of Credit and Reimbursement Agreements. The LOCs are secured by mortgage bonds issued under TEP's 1992 Mortgage.

In November 2011, TEP repurchased $150 million of variable rate bonds. TEP did not cancel the repurchased bonds, which remained outstanding under their respective indentures but were not reflected as debt on the balance sheet. See 2011 TEP Unsecured Notes below.

In December 2010, TEP issued $37 million of Coconino County, Arizona, tax-exempt pollution control bonds (2010 Coconino Bonds). The 2010 Coconino Bonds are supported by a LOC, which is secured by $37 million of 1992 Mortgage Bonds and expires December 2014. The bonds accrue interest at a variable weekly rate and are due October 2032. These bonds are multi-modal bonds that allow TEP to change the interest feature of the bonds. They are callable at any time at par plus accrued interest and are subject to mandatory redemption under certain circumstances if the LOC is not extended. The average interest rate on TEP's 2010 Coconino Bonds was 0.22% in 2012 and 0.23% in 2011. TEP used the proceeds to redeem a corresponding principal amount of fixed rate Coconino pollution control bonds. TEP capitalized less than $1 million in costs related to the issuance of these bonds and will amortize the costs to Interest Expense – Long-Term Debt in the income statements through October 2032, the term of the bonds.

The following table shows interest rates on TEP's variable rate bonds which are reset weekly by its remarketing agents:

	Years Ended December 31,		
	2012	**2011**	**2010**
Interest Rates on Bonds:			
Average Interest Rate	0.17%	0.18%	0.26%
Range of Average Weekly Rates	0.06% to 0.26%	0.05% to 0.34%	0.17% to 0.39%

In August 2009, TEP entered into an interest rate swap that had the effect of converting $50 million of variable rate bonds to a fixed rate of 2.4% from September 2009 to September 2014.

Unsecured Fixed Rate Bonds

At December 31, 2012, TEP had $609 million in unsecured fixed rate bonds. At December 31, 2011, TEP had $616 million outstanding.

In March 2012, the Industrial Development Authority of Apache County, Arizona issued $177 million of unsecured tax-exempt pollution control bonds on behalf of TEP. The bonds bear interest at a fixed rate of 4.5%, mature in March 2030, and may be redeemed at par on or after March 1, 2022. The proceeds from the sale of the bonds, together with $7 million of principal and $1 million for accrued interest provided by TEP, were deposited with a trustee to retire $184 million of unsecured tax-exempt bonds with interest rates of 5.85% and 5.875% and maturity dates ranging from 2026 to 2033. TEP's $8 million payment to the trustee was the only cash flow activity since proceeds from the newly-issued bonds were not received or disbursed by TEP. TEP capitalized approximately $2 million in costs related to the issuance of the bonds and will amortize the costs to Interest Expense – Long-Term Debt in the income statements through March 2030, the term of the bonds.

In June 2012, the Industrial Development Authority of Pima County, Arizona issued approximately $16 million of unsecured tax-exempt industrial development bonds on behalf of TEP. The bonds bear interest at a fixed rate of 4.5%, mature in June 2030, and may be redeemed at par on or after June 1, 2022. The proceeds from the sale of the bonds together with $0.4 million accrued interest provided by TEP, were deposited with a trustee to retire approximately $16 million of outstanding unsecured tax-exempt bonds with interest rates of 5.85% and 5.875%, and maturity dates ranging from 2026 to 2033. TEP's payment of accrued interest was the only cash flow activity since proceeds from the newly-issued bonds were not received or disbursed by TEP. TEP capitalized less than $0.5 million in costs related to the issuance of the bonds and will amortize the costs to Interest Expense – Long-Term Debt in the income statements through June 2030, the term of the bonds.

In November 2011, TEP redeemed $22 million in unsecured fixed rate bonds. See 2011 TEP Unsecured Notes below.

In October 2010, TEP issued $100 million of Pima County, Arizona tax-exempt IDBs. The IDBs are unsecured, bear interest at a rate of 5.25%, mature in October 2040, and are callable at par on or after October 1, 2020. Net of an underwriting discount, $99 million of proceeds were deposited in a construction fund with the bond trustee. The proceeds were applied to the construction of certain of TEP's transmission and distribution facilities used to provide electric service in Pima County. TEP drew down $88 million of the proceeds from the construction fund in 2010 and $11 million in 2011. TEP capitalized approximately $1 million in costs related to the issuance of these bonds and will amortize the costs to Interest Expense-Long-Term Debt in the income statements through October 2040, the term of the bonds.

2012 TEP Unsecured Notes

In September 2012, TEP issued $150 million of 3.85% unsecured notes due March 2023. TEP may call the debt prior to December 15, 2022, with a make-whole premium plus accrued interest. After December 15, 2022, TEP may call the debt at par plus accrued interest. The unsecured notes contain a limitation on the amount of secured debt that TEP may have outstanding. TEP used the net proceeds to repay approximately $72 million outstanding on the revolving credit facility, with the remaining proceeds used for general corporate purposes. TEP capitalized approximately $1 million in costs related to the issuance of unsecured notes and will amortize the costs to Interest Expense – Long-Term Debt in the income statements through March 2023, the term of the unsecured notes.

2011 TEP Unsecured Notes

In November 2011, TEP issued $250 million of 5.15% unsecured notes due November 2021. TEP may call the debt any time before August 15, 2021, with a make-whole premium plus accrued interest. After August 15, 2021, the debt is callable at par plus accrued interest. TEP used the net proceeds from the sale to: 1) repurchase $150 million of variable rate bonds; 2) redeem $22 million of 6.1% fixed rate bonds; and 3) repay $78 million of outstanding revolving credit facility balances, with the remaining proceeds applied to general corporate purposes. The variable rate bonds were supported by LOCs issued under TEP's Credit Facility. As a result of the repurchase of the variable rate bonds, TEP cancelled $155 million of LOCs and reduced its mortgage bonds supporting the LOCs by the same amount. TEP capitalized $2 million in costs related to the issuance of the notes and will amortize the costs to Interest Expense-Long-Term Debt in the income statements through November 2021, the term of the unsecured notes.

1992 Mortgage

TEP's 1992 Mortgage creates liens on and security interests in most of TEP's utility plant assets, with the exception of Springerville Unit 2. San Carlos Resources Inc., a wholly-owned subsidiary of TEP, holds title to Springerville Unit 2. Utility Plant under Capital Leases is not subject to such liens nor is it available to TEP creditors, other than the lessors. The net book value of TEP's utility plant subject to the lien of the indenture was approximately $2 billion at December 31, 2012, and December 31, 2011.

TEP CAPITAL LEASE OBLIGATIONS

Springerville Leases

The terms of TEP's capital leases are as follows:

- The Springerville Unit 1 Leases have an initial term to January 2015 and provide for renewal periods of three or more years through 2030. TEP has a fair market value purchase option for facilities under the Springerville Unit 1 Lease. In December 2011, TEP and the owner participants of the Springerville Unit 1 Leases completed a formal appraisal process to determine the fair market value purchase price, in accordance with the Springerville Unit 1 Leases agreements. Based on that appraisal, TEP would have to pay $159 million in 2015 for the 86% interest not already owned by TEP. In 2012, TEP initiated a proceeding seeking judicial confirmation of the results of the appraisal process in federal district court. In the proceeding, the owner participants alleged that the appraisal process failed to yield a legitimate purchase price for the leased interest. In January 2013, the federal district court denied TEP's petition on the grounds that the court lacks jurisdiction in the matter. In February 2013, TEP appealed the matter to the U.S. Court of Appeals for the Ninth Circuit.
- The Springerville Coal Handling Facilities Leases have an initial term to April 2015 and provide for fixed-rate lease renewal options if certain conditions are satisfied as well as a fixed-price purchase provision of $120 million. The lease provides for one renewal period of six years beginning in April 2015, with additional renewal periods of five or more years through 2035.
- The Springerville Common Facilities Leases 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. Instead of extending the leases TEP may exercise a fixed-price purchase provision. The fixed prices for the acquisition of common facilities are $38 million in 2017 and $68 million in 2021.

TEP agreed with Tri-State, the owner of Springerville Unit 3, and SRP, the owner of Springerville Unit 4, that if the Springerville Coal Handling Facilities and Common Facilities Leases are not renewed, TEP will exercise the purchase options under these contracts. SRP will then be obligated to buy a portion of these facilities and Tri-State will then be obligated to either: 1) buy a portion of these facilities; or 2) continue making payments to TEP for the use of these facilities.

In January 2013, through scheduled lease payments, TEP reduced its capital lease obligations by $82 million.

LEASE DEBT AND EQUITY

Investments in Springerville Lease Debt and Equity

TEP's investments in Springerville Unit 1 lease debt totaled $9 million at December 31, 2012, and $29 million at December 31, 2011. In January 2013, TEP received the final maturity payment of $9 million on the investment in Springerville Unit 1 lease debt. TEP also held an undivided equity ownership interest in the Springerville Unit 1 Leases totaling $36 million at December 31, 2012, and $37 million at December 31, 2011.

Interest Rate Swaps—Springerville Common Facilities Lease Debt

TEP's interest rate swaps hedge the floating interest rate risk associated with the Springerville Common Facilities lease debt. Interest on the lease debt is payable at six-month London Interbank Offered Rate (LIBOR) plus a spread. The applicable spread was 1.75% at December 31, 2012, and 1.625% at December 31, 2011.

The swaps have the effect of fixing the interest rates on the amortizing principal balances as follows:

Outstanding at December 31, 2012	Fixed Ratio	LIBOR Spread
$ 34 million	5.77%	1.75%
$ 19 million	3.18%	1.75%
$ 6 million	3.32%	1.75%

TEP recorded these interest rate swaps as a cash flow hedge for financial reporting purposes. See Note 16.

UNS ELECTRIC SENIOR UNSECURED NOTES

UNS Electric has $100 million of senior unsecured notes: $50 million at 6.5%, due 2015 and $50 million at 7.1%, due 2023. The UNS Electric long-term notes are guaranteed by UES. The notes may be prepaid with a make-whole call premium reflecting a discount rate equal to an equivalent maturity United States Treasury security yield plus 50 basis points.

UNS Electric's long-term notes contain certain restrictive covenants, including restrictions on transactions with affiliates, mergers, liens to secure indebtedness, restricted payments, and incurrence of indebtedness.

UNS ELECTRIC TERM LOAN CREDIT AGREEMENT AND INTEREST RATE SWAP

In August 2011, UNS Electric entered into a four-year $30 million variable rate term loan credit agreement. UNS Electric used the $30 million in proceeds to repay borrowings under its revolving credit facility. The interest rate currently in effect is three-month LIBOR plus 1.125%. At the same time, UNS Electric entered into a fixed-for-floating interest rate swap in which UNS Electric will pay a fixed rate of 0.97% and receive a three-month LIBOR rate on a $30 million notional amount over a four-year period ending August 2015. The UNS Electric term loan credit agreement, included in Long-Term Debt on the balance sheet, is guaranteed by UES.

The term loan credit agreement contains certain restrictive covenants for UNS Electric and UES. The covenants include restrictions on transactions with affiliates, restricted payments, additional indebtedness, liens, and mergers. UNS Electric must meet an interest coverage ratio to issue additional debt. However, UNS Electric may, without meeting these tests, refinance indebtedness and incur short-term debt in an amount not to exceed $5 million. The credit agreement also requires UNS Electric to maintain a maximum leverage ratio, and allows UNS Electric to pay dividends so long as it maintains compliance with the credit agreement.

UNS GAS SENIOR UNSECURED NOTES

In August 2011, UNS Gas issued $50 million of senior guaranteed notes at 5.39% due August 2026. UNS Gas used the proceeds to pay in full the $50 million of UNS Gas 6.23% notes that matured in August 2011. UNS Gas has another $50 million of notes at 6.23% due August 2015. The notes may be prepaid with a make-whole call premium reflecting a discount rate equal to an equivalent maturity United States Treasury security yield plus 50 basis points. UES guarantees the notes. UNS Gas capitalized less than $0.5 million of costs related to the issuance of the notes and will amortize these costs over the life of the notes.

UNS Gas' long-term debt contains certain restrictive covenants, including restrictions on transactions with affiliates, mergers, liens to secure indebtedness, restricted payments, and incurrence of indebtedness.

UNS ENERGY CREDIT AGREEMENT

In November 2011, UNS Energy amended its existing credit agreement to extend the expiration date from November 2014 to November 2016.

In November 2010, UNS Energy amended and restated its existing credit agreement. As amended, the agreement consists of a $125 million revolving credit facility and revolving letter of credit facility. UNS Energy's obligations under the agreement are secured by a pledge of the capital stock of Millennium, UES, and UED.

UNS Energy capitalized less than $0.5 million related to the 2011 credit agreement amendment and $1 million related to the 2010 credit agreement amendment and restatement, and will amortize these costs through November 2016.

UNS Energy had $45 million of outstanding borrowings at December 31, 2012, and $57 million of outstanding borrowings at December 31, 2011, under its revolving credit facility. The weighted average interest rate on the revolver was 1.96% at December 31, 2012, and 2.04% at December 31, 2011. We reflected the revolver borrowings in Long-Term Debt on the balance sheet as UNS Energy has the ability and the intent to have outstanding borrowings for the next twelve months. As of February 13, 2013, outstanding borrowings under the UNS Credit Agreement were $45 million.

Interest rates and fees under the UNS Energy Credit Agreement are based on a pricing grid tied to UNS Energy's credit ratings. The interest rate currently in effect on borrowings is LIBOR plus 1.75% for Eurodollar loans or Alternate Base Rate plus 0.75% for Alternate Base Rate loans.

The UNS Energy Credit Agreement contains a number of covenants which restrict UNS Energy and its subsidiaries, including restrictions on additional indebtedness, liens, mergers, and sales of assets. The UNS Energy Credit Agreement also requires UNS Energy to meet a minimum cash flow to interest coverage ratio determined on a UNS Energy standalone basis and not to exceed a maximum leverage ratio determined on a consolidated basis. Under the UNS Energy Credit Agreement, UNS Energy may pay dividends so long as it maintains compliance with the agreement.

TEP CREDIT AGREEMENT

In December 2011, TEP reduced its letter of credit facility from $341 million to $186 million, following the repurchase of $150 million of variable rate bonds and the cancellation of $155 million of LOCs supporting those bonds.

In November 2011, TEP amended its existing credit agreement to extend the expiration date from November 2014 to November 2016.

In November 2010, TEP amended and restated its existing credit agreement, consisting of a $200 million revolving credit, revolving LOC facility, and a $341 million LOC facility to support tax-exempt bonds.

The TEP credit facility is secured by $386 million of mortgage bonds issued under the 1992 Mortgage, which creates a lien on and security interest in most of TEP's utility plant assets.

TEP capitalized $1 million related to the 2011 credit agreement amendment and $4 million related to the 2010 credit agreement amendment and restatement, and will amortize these costs through November 2016.

Interest rates and fees under the TEP Credit Agreement are based on a pricing grid tied to TEP's credit ratings. The interest rate currently in effect on borrowings is LIBOR plus 1.125% for Eurodollar loans or Alternate Base Rate plus 0.125% for Alternate Base Rate loans. The margin rate currently in effect on the $186 million letter of credit facility is 1.125%.

The TEP Credit Agreement contains a number of covenants which restrict TEP and its subsidiaries, including restrictions on liens, mergers, and sale of assets. The TEP Credit Agreement also requires TEP not to exceed a maximum leverage ratio. Under the TEP Credit Agreement, TEP may pay dividends to UNS Energy so long as it maintains compliance with the agreement.

As of December 31, 2012, TEP had no borrowings outstanding and $1 million in LOCs issued under its revolving credit facility. As of December 31, 2011, TEP had $10 million in borrowings and $1 million outstanding in LOCs under its revolving credit facility. The revolving loan balance was included in Current Liabilities on UNS Energy's and TEP's balance sheets. The outstanding LOCs are off-balance sheet obligations of TEP. As of February 13, 2013, TEP had $30 million in borrowings and $1 million outstanding in LOCs under its revolving credit facility.

2010 TEP REIMBURSEMENT AGREEMENT

A $37 million letter of credit was issued pursuant to the 2010 TEP Reimbursement Agreement. The letter of credit supports $37 million aggregate principal amount of variable rate tax-exempt bonds that were issued on behalf of TEP in December 2010, see Variable Rate Tax-Exempt Bonds, above.

The 2010 TEP Reimbursement Agreement is secured by $37 million of mortgage bonds issued under TEP's 1992 Mortgage. Fees are payable on the aggregate outstanding amount of the letter of credit at a rate of 1.50% per annum.

The 2010 TEP Reimbursement Agreement contains substantially the same restrictive covenants as the TEP Credit Agreement described above.

UNS GAS/UNS ELECTRIC REVOLVER

In November 2011, UNS Gas and UNS Electric amended their existing unsecured credit agreement to extend the expiration date from November 2014 to November 2016.

In November 2010, UNS Gas and UNS Electric amended and restated their existing unsecured credit agreement. As amended, the UNS Gas/UNS Electric Revolver consists of a $100 million revolving credit and revolving letter of credit facility. The maximum borrowings outstanding at any one time for UNS Gas or UNS Electric under the agreement may not exceed $70 million. UNS Gas and UNS Electric each are liable for only their own individual borrowings under the UNS Gas/UNS Electric Revolver. UES guarantees the obligations of both UNS Gas and UNS Electric. The UNS Gas/UNS Electric Revolver may be used to issue LOCs, as well as for revolver borrowings. UNS Gas and UNS Electric issue LOCs, which are off-balance sheet obligations, to support power and gas purchases and hedges.

UNS Gas and UNS Electric capitalized less than $0.5 million of costs related to the 2011 credit agreement amendment and $1 million related to the 2010 credit agreement amendment and restatement, and will continue to amortize these costs through November 2016 to Interest Expense – Long-Term Debt in the income statements.

Interest rates and fees under the UNS Gas/UNS Electric Revolver are based on a pricing grid tied to their credit ratings. The interest rate currently in effect on borrowings is LIBOR plus 1.25% for Eurodollar loans or Alternate Base Rate plus 0.25% for Alternate Base Rate loans.

The UNS Gas/UNS Electric Revolver contains a number of covenants which impose restrictions on UNS Gas, UNS Electric, and UES, including restrictions on additional indebtedness, liens, and mergers. The UNS Gas/UNS Electric Revolver also stipulates a maximum leverage ratio. Under the terms of the UNS Gas/UNS Electric Revolver, UNS Gas and UNS Electric may pay dividends so long as they maintain compliance with the agreement.

UNS Electric had less than $0.5 million in outstanding LOCs under the UNS Gas/UNS Electric Revolver as of December 31, 2012, and $6 million outstanding as of December 31, 2011. These balances are not shown on the balance sheet.

OTHER

At December 31, 2012, UNS Energy and its subsidiaries were in compliance with the terms of their respective loan, note purchase, and credit agreements. No amounts of net income were subject to dividend restrictions.

DEBT MATURITIES

Long-term debt, including term loan payments, revolving credit facilities classified as long-term, and capital lease obligations mature on the following dates:

	TEP Variable Rate Bonds Supported by Letters of Credit[1]	TEP Scheduled Debt Retirements[2]	TEP Capital Lease Obligations	TEP Total	UNS Gas	UNS Electric	UNS Energy Parent Company	Total
			-Millions of Dollars-					
2013	$—	$ —	$121	$ 121	$—	$—	$—	$ 121
2014	37	—	194	231	—	—	—	231
2015	—	—	23	23	50	80	—	153
2016	178	—	17	195	—	—	45	240
2017	—	—	18	18	—	—	—	18
Total 2013 – 2017	215	—	373	588	50	80	45	763
Thereafter	—	1,009	42	1,051	50	50	—	1,151
Less: Imputed Interest	—	—	(62)	(62)	—	—	—	(62)
Total	$215	$1,009	$353	$1,577	$100	$130	$ 45	$1,852

(1) TEP's variable rate bonds are backed by $186 million in LOCs issued pursuant to TEP's Credit Agreement which expires in November 2016 and TEP's $37 million Reimbursement Agreement which expires in December 2014. Although the variable rate bonds mature between 2018 and 2032, the above table reflects a redemption or repurchase of such bonds in 2014 and 2016 as though the LOCs terminate without replacement upon expiration of the TEP Credit Agreement.

(2) The repayment of TEP Unsecured Notes is not reduced by the approximately $1 million discount.

NOTE 7. STOCKHOLDERS' EQUITY

DIVIDEND LIMITATIONS

UNS Energy

UNS Energy's ability to pay cash dividends on Common Stock outstanding depends, in part, upon cash flows from our subsidiaries: TEP, UES, Millennium, and UED, as well as compliance with various debt covenant requirements. UNS Energy and each of its subsidiaries were in compliance with debt covenants at December 31, 2012; therefore, TEP and the other subsidiaries were not restricted from paying dividends.

In February 2013, UNS Energy declared a first quarter dividend to shareholders of $0.435 per share of UNS Energy Common Stock. The dividend, totaling approximately $18 million, will be paid on March 25, 2013, to common shareholders of record as of March 13, 2013.

In the first half of 2012, $147 million of the Convertible Senior Notes outstanding were converted into approximately 4.3 million shares of UNS Energy Common Stock increasing common stock equity by $147 million.

TEP

The Federal Power Act states that an electric utility's dividends shall not be paid out of funds properly included in capital accounts. TEP has an accumulated deficit rather than positive retained earnings. Although the terms of the Federal Power Act are unclear, we believe that there is a reasonable basis for TEP to pay dividends from current year earnings. TEP paid dividends to UNS Energy of $30 million in 2012; no dividends were paid in 2011; and $60 million were paid in 2010.

UNS Energy did not contribute capital to TEP in 2012 but made capital contributions of $30 million in 2011 and $15 million in 2010.

NOTE 8. INCOME TAXES

A reconciliation of the federal statutory income tax rate to each company's effective income tax rate follows:

	UNS Energy			TEP		
	Years Ended December 31,					
	2012	2011	2010	2012	2011	2010
	-Millions of Dollars-					
Federal Income Tax Expense at Statutory Rate	$ 51	$ 62	$66	$ 37	$ 48	$ 58
State Income Tax Expense, Net of Federal Benefit	7	8	9	5	6	8
Deferred Tax Asset Valuation Allowance	—	—	8	—	—	—
Deferred Tax Asset Write-off Related to Unregulated Investment	—	—	3	—	—	—
AFUDC Equity	(1)	(1)	(1)	(1)	(1)	(1)
Domestic Production Deduction	—	—	(3)	—	—	(3)
Federal/State Tax Credits	(1)	(3)	(2)	(1)	(2)	(2)
Other	—	1	(3)	(1)	1	—
Total Federal and State Income Tax Expense	$ 56	$ 67	$77	$ 39	$ 52	$ 60
Effective Tax Rate	38%	38%	41%	37%	38%	36%

In 2010, UNS Energy recorded a $3 million out-of-period income tax expense. The out-of-period expense related to the write-off of a previously recorded deferred tax asset associated with the excess of tax over book basis difference in a consolidated unregulated investment. Management concluded that this out-of-period adjustment was not material to current and prior period financial statements.

Income tax expense included in the income statements consists of the following:

	UNS Energy			TEP		
	Years Ended December 31,					
	2012	2011	2010	2012	2011	2010
	-Millions of Dollars-					
Current Tax Expense (Benefit)						
Federal	$ (2)	$ (7)	$34	$ (4)	$ (5)	$ 28
State	(2)	(2)	7	(2)	(2)	7
Total	(4)	(9)	41	(6)	(7)	35
Deferred Tax Expense (Benefit)						
Federal	51	64	32	38	50	24
Federal Investment Tax Credits	—	(1)	(1)	—	(1)	(1)
State	9	13	5	7	10	2
Total	60	76	36	45	59	25
Total Federal and State Income Tax Expense	$ 56	$ 67	$77	$ 39	$ 52	$ 60

The significant components of deferred income tax assets and liabilities consist of the following:

	UNS Energy		TEP	
	December 31,		December 31,	
	2012	2011	2012	2011
	-Millions of Dollars-			
Gross Deferred Income Tax Assets				
Capital Lease Obligations	$ 141	$ 169	$ 141	$ 169
Net Operating Loss Carryforwards	72	81	85	76
Customer Advances and Contributions in Aid of Construction	34	30	19	17
Alternative Minimum Tax Credit	43	43	24	25
Accrued Postretirement Benefits	23	23	23	23
Renewable Energy Credit Up-Front Incentive Payments	26	22	20	18
Emission Allowance Inventory	10	10	10	10
Unregulated Investment Losses	9	9	—	—
Other	44	34	43	29
Gross Deferred Income Tax Assets	402	421	365	367
Deferred Tax Assets Valuation Allowance	(7)	(7)	—	—
Gross Deferred Income Tax Liabilities				
Plant – Net	(648)	(585)	(571)	(516)
Capital Lease Assets – Net	(34)	(41)	(34)	(41)
Pensions	(23)	(17)	(24)	(18)
PPFAC	(6)	(19)	(3)	(16)
Other	(15)	(29)	(15)	(17)
Gross Deferred Income Tax Liabilities	(726)	(691)	(647)	(608)
Net Deferred Income Tax Liabilities	$(331)	$(277)	$(282)	$(241)

The net deferred income tax liability on the balance sheet is as follows:

	UNS Energy		TEP	
	December 31,		December 31,	
	2012	2011	2012	2011
	-Millions of Dollars-			
Deferred Income Taxes – Current Assets	$ 34	$ 23	$ 37	$ 22
Deferred Income Taxes – Noncurrent Liabilities	(365)	(300)	(319)	(263)
Net Deferred Income Tax Liability	$(331)	$(277)	$(282)	$(241)

The $9 million unregulated investment loss deferred tax asset includes $7 million of capital loss at December 31, 2012, and December 31, 2011. The deferred tax asset can only be used if the company has capital gains to offset the losses. Management believes that it is more likely than not that the company will not be able to generate future capital gains. As a result, UNS Energy recorded a $7 million valuation allowance against the deferred tax asset as of December 31, 2012, and December 31, 2011. Management believes that based on its historical pattern of taxable income, UNS Energy will produce sufficient income in the future to realize all other deferred income tax assets.

Income Tax Position

As of December 31, 2012, UNS Energy and TEP had the following carryforward amounts:

	UNS Energy		TEP	
	Amount	Expiring Year	Amount	Expiring Year
	-Amounts in Millions of Dollars-			
Capital Loss	$ 8	2015	$—	—
Federal Net Operating Loss	202	2031-32	233	2031-32
State Net Operating Loss	14	2032	57	2016-32
State Credits	2	2016-17	4	2016-17
AMT Credit	43	None	24	None

State Tax Rate Change

In the first quarter of 2011, the Arizona legislature passed a bill reducing the corporate income tax rate from the current rate of 6.968%. The tax rate reduction will be phased in beginning in 2014, with a reduction of approximately 0.5% per year until the income tax rate reaches 4.9% for 2017 and later years. As a result of these tax rate reductions, we reduced the net deferred tax liabilities at UNS Energy and TEP by $13 million, offset entirely by adjustments to regulatory assets and liabilities. The income tax rate change did not have an impact on UNS Energy's and TEP's effective tax rate for 2012 or 2011.

Excess Tax Benefit Realized from Share-Based Compensation Plans

UNS Energy records excess tax benefits as an increase to Common Stock when tax deductions for share-based compensation exceed the expense recorded in the financial statements and they result in a reduction to income taxes payable. As of December 31, 2012, UNS Energy had $2 million of excess tax benefits that were not recorded in Common Stock. The excess benefits will be recorded in Common Stock when the Federal net operating loss carryforwards of $202 million are used.

Uncertain Tax Positions

In accordance with accounting rules related to uncertain tax positions, we are required to determine whether it is more likely than not that we will sustain an income tax position under examination. Each income tax position is measured to determine the amount of benefit to recognize in the financial statements. The following table shows the changes in unrecognized tax benefits of UNS Energy and TEP:

	UNS Energy		TEP	
	December 31,		December 31,	
	2012	2011	2012	2011
	-Millions of Dollars-			
Unrecognized Tax Benefits, Beginning of Year	$ 29	$ 41	$ 24	$ 35
Additions Based on Tax Positions Taken in the Current Year	5	9	3	8
Reductions Based on Settlements with Tax Authorities	(4)	(22)	(4)	(19)
Additions Based on Tax Positions Taken in the Prior Year	—	1	—	—
Unrecognized Tax Benefits, End of Year	$ 30	$ 29	$ 23	$ 24

Unrecognized tax benefits of $1 million, if recognized, would reduce the effective tax rate at December 31, 2012, and December 31, 2011, for both UNS Energy and TEP. The balance in unrecognized tax benefits could change in the next 12 months as a result of ongoing IRS audits, but we are unable to determine the amount of the change.

UNS Energy and TEP recognize interest accrued related to unrecognized tax benefits in Other Interest Expense in the income statements. UNS Energy and TEP did not recognize a reduction to interest expense in 2012. A reduction to Other Interest Expense of $1 million was recorded in 2011. The balance of interest payable for UNS Energy and TEP was $1 million at both December 31, 2012 and December 31, 2011. We have no penalties accrued in the years presented.

UNS Energy and TEP have been audited by the IRS through tax year 2008 and are currently under audit by the IRS for 2009 and 2010. We are unable to determine when the audits will be completed. UNS Energy and TEP are not currently under audit by any state tax agencies.

NOTE 9. EMPLOYEE BENEFIT PLANS

PENSION BENEFIT PLANS

Pension Contributions

The Pension Protection Act of 2006 (The Pension Act) established minimum funding targets for pension plans. A plan's funding target is the present value of all benefits accrued or earned as of the beginning of the plan year. While the annual targets are not legally required, benefit payment options are limited for plans that do not meet the targets, and a funding deficiency notice must be sent to all plan participants. Our plans are in compliance with The Pension Act.

In 2013, UNS Energy expects to contribute $24 million to the pension plans, including $22 million in contributions by TEP.

OTHER RETIREE BENEFIT PLANS

TEP provides limited health care and life insurance benefits for retirees. Active TEP employees may become eligible for these benefits if they reach retirement age while working for TEP or an affiliate. UNS Gas and UNS Electric provide retiree medical benefits for current retirees. UNS Gas and UNS Electric active employees are not eligible for retiree medical benefits.

TEP has a Voluntary Employee Beneficiary Association (VEBA) to fund its other retiree benefit plan related to classified employees. TEP contributed $3 million in 2012, and $2 million in each of 2011 and 2010 to the VEBA. We record changes in other retiree obligation, not yet reflected in net periodic benefit cost, as a regulatory asset, as such amounts are probable of future recovery in the rates charged to retail customers. Other retiree benefits for unclassified employees are funded on a year-by-year basis.

TEP's retiree medical plan was amended effective December 31, 2011, to increase the participant contributions for unclassified employees who retire on or after July 1, 2012. TEP's retiree medical plan was amended in 2012, to increase the participant contributions for classified employees who retire after February 1, 2014.

The pension and other retiree benefit related amounts (excluding tax balances) included on the UNS Energy balance sheet are:

	Pension Benefits		Other Retiree Benefits	
	Years Ended December 31,			
	2012	2011	2012	2011
	-Millions of Dollars-			
Regulatory Pension Asset Included in Other Regulatory Assets	$129	$106	$ 10	$ 8
Accrued Benefit Liability Included in Accrued Employee Expenses	(1)	(1)	(2)	(2)
Accrued Benefit Liability Included in Pension and Other Retiree Benefits	(90)	(72)	(69)	(66)
Accumulated Other Comprehensive Loss (related to SERP)	4	2	—	—
Net Amount Recognized	$ 42	$ 35	$ (61)	$ (60)

The table above includes accrued pension benefit liabilities for UNS Gas and UNS Electric of approximately $9 million at December 31, 2012, and $8 million at December 31, 2011. The table also includes a retiree benefit liability of $1 million for UNS Gas and UNS Electric for each period presented.

OBLIGATIONS AND FUNDED STATUS

We measured the actuarial present values of all pension benefit obligations and other retiree benefit plans at December 31, 2012, and December 31, 2011. The table below includes TEP's, UNS Gas', and UNS Electric's plans. The change in projected benefit obligation and plan assets and reconciliation of the funded status are as follows:

	Pension Benefits		Other Retiree Benefits	
	Years Ended December 31,			
	2012	2011	2012	2011
	-Millions of Dollars-			
Change in Projected Benefit Obligation				
Benefit Obligation at Beginning of Year	$319	$283	$ 73	$ 73
Actuarial (Gain) Loss	51	22	3	—
Interest Cost	15	16	3	4
Service Cost	10	10	3	3
Amendments	—	—	—	(2)
Benefits Paid	(15)	(12)	(4)	(5)
Projected Benefit Obligation at End of Year	380	319	78	73
Change in Plan Assets				
Fair Value of Plan Assets at Beginning of Year	245	220	5	4
Actual Return on Plan Assets	36	14	1	—
Benefits Paid	(15)	(12)	(4)	(5)
Employer Contributions [1]	23	23	5	6
Fair Value of Plan Assets at End of Year	289	245	7	5
Funded Status at End of Year	$ (91)	$ (74)	$ (71)	$ (68)

[1] TEP made $20 million in pension contributions and $5 million of other retiree benefits contributions in 2012 and 2011.

The table above includes the following for UNS Gas and UNS Electric:

- Pension benefit obligations of $23 million at December 31, 2012, and $18 million at December 31, 2011;

- Plan assets of $14 million at December 31, 2012, and $10 million at December 31, 2011; and
- A retiree benefit obligation of $1 million at December 31, 2012, and at December 31, 2011.

The following table provides the components of UNS Energy's regulatory assets and accumulated other comprehensive loss that have not been recognized as components of net periodic benefit cost as of the dates presented:

	Pension Benefits		Other Retiree Benefits	
	Years Ended December 31,			
	2012	2011	2012	2011
	-Millions of Dollars-			
Net Loss	$133	$108	$13	$11
Prior Service Cost (Benefit)	1	1	(3)	(3)

Information for pension plans with Accumulated Benefit Obligations in excess of pension plan assets follows:

	December 31,	
	2012	2011
	-Millions of Dollars-	
Projected Benefit Obligation at End of Year	$380	$319
Accumulated Benefit Obligation at End of Year	334	281
Fair Value of Plan Assets at End of Year	289	245

At December 31, 2012, and December 31, 2011, all UNS Energy defined benefit pension plans had accumulated benefit obligations in excess of pension plan assets.

The components of net periodic benefit costs are as follows:

	Pension Benefits			Other Retiree Benefits		
	Years Ended December 31,					
	2012	2011	2010	2012	2011	2010
	-Millions of Dollars-					
Service Cost	$ 10	$ 10	$ 8	$ 3	$ 3	$ 3
Interest Cost	16	15	15	3	4	4
Expected Return on Plan Assets	(17)	(16)	(14)	—	—	—
Prior Service Cost Amortization	—	—	—	—	(1)	(2)
Recognized Actuarial Loss	7	6	5	—	—	—
Net Periodic Benefit Cost	$ 16	$ 15	$ 14	$ 6	$ 6	$ 5

Approximately 20% of the net periodic benefit cost was capitalized as a cost of construction and the remainder was included in current year earnings.

The changes in plan assets and benefit obligations recognized as regulatory assets or in AOCI are as follows:

	Pension Benefits					
	2012		2011		2010	
	Regulatory Asset	AOCI	Regulatory Asset	AOCI	Regulatory Asset	AOCI
	-Millions of Dollars-					
Current Year Actuarial (Gain) Loss	$30	$ 1	$25	$ (2)	$16	$ 1
Amortization of Actuarial Gain (Loss)	(7)	—	(5)	—	(5)	—
Total Recognized (Gain) Loss	$23	$ 1	$20	$ (2)	$11	$ 1

	Other Retiree Benefits		
	2012	2011	2010
	Regulatory Asset	Regulatory Asset	Regulatory Asset
	-Millions of Dollars-		
Prior Service Cost (Credit)	$ —	$ (2)	$—
Current Year Actuarial (Gain) Loss	2	—	(1)
Amortization of Actuarial (Gain) Loss	—	—	(1)
Amortization of Prior Service (Cost) Credit	—	1	2
Total Recognized (Gain) Loss	$ 2	$ (1)	$—

For all pension plans, we amortize prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan. We will amortize $9 million estimated net loss from other regulatory assets and less than $0.5 million prior service cost from AOCI into net periodic benefit cost in 2013. The estimated net loss for the defined benefit postretirement plans that will be amortized from other regulatory assets into net periodic benefit cost in 2013 is less than $1 million. The estimated prior service benefit that will be amortized is less than $1 million.

	Pension Benefits		Other Retiree Benefits	
	2012	2011	2012	2011
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31,				
Discount Rate	4.1%-4.3%	4.9%-5.0%	3.8%	4.7%
Rate of Compensation Increase	3.0%	3.0%	N/A	N/A

	Pension Benefits			Other Retiree Benefits		
	2012	2011	2010	2012	2011	2010
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31,						
Discount Rate	4.9% - 5.0%	5.5% - 5.6%	6.3%	4.7%	5.2%	6.0%
Rate of Compensation Increase	3.0%	3.0% - 5.0%	3.0% - 5.0%	N/A	N/A	N/A
Expected Return on Plan Assets	7.0%	7.0%	7.5%	7.0%	5.1%	5.6%

Net periodic benefit cost is subject to various assumptions and determinations, such as the discount rate, the rate of compensation increase, and the expected return on plan assets.

We use a combination of sources in selecting the expected long-term rate-of-return-on-assets assumption, including an investment return model. The model used provides a "best-estimate" range over 20 years from the 25th percentile to the 75th percentile. The model, used as a guideline for selecting the overall rate-of-return-on-assets assumption, is based on forward looking return expectations only. The above method is used for all asset classes.

Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as net periodic benefit cost. The assumed health care cost trend rates follow:

	December 31,	
	2012	2011
Health Care Cost Trend Rate Assumed for Next Year	6.9%	6.9%
Ultimate Health Care Cost Trend Rate Assumed	4.5%	4.5%
Year that the Rate Reaches the Ultimate Trend Rate	2027	2027

Assumed health care cost trend rates significantly affect the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects on the December 31, 2012, amounts:

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	-Millions of Dollars-	
Effect on Total Service and Interest Cost Components	$1	$(1)
Effect on Retiree Benefit Obligation	6	(5)

PENSION PLAN AND OTHER RETIREE BENEFIT ASSETS

Pension Assets

We calculate the fair value of plan assets on December 31, the measurement date. Pension plan asset allocations, by asset category, on the measurement date were as follows:

	TEP Plan Assets		UNS Gas and UNS Electric Plan Assets	
	2012	2011	2012	2011
Asset Category				
Equity Securities	50%	49%	56%	55%
Fixed Income Securities	41	42	33	34
Real Estate	7	7	11	11
Other	2	2	—	—
Total	100%	100%	100%	100%

The following tables set forth the fair value measurements of pension plan assets by level within the fair value hierarchy:

	Fair Value Measurements of Pension Assets December 31, 2012			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	- Millions of Dollars -			
Asset Category				
Cash Equivalents	$ 1	$—	$—	$ 1
Equity Securities:				
United States Large Cap	—	71	—	71
United States Small Cap	—	15	—	15
Non-United States	—	59	—	59
Fixed Income	—	116	—	116
Real Estate	—	8	13	21
Private Equity	—	—	6	6
Total	$ 1	$269	$ 19	$289

	Fair Value Measurements of Pension Assets December 31, 2011			
	Level 1	Level 2	Level 3	Total
	- Millions of Dollars -			
Asset Category				
Cash Equivalents	$ 1	$—	$—	$ 1
Equity Securities:				
United States Large Cap	—	61	—	61
United States Small Cap	—	13	—	13
Non-United States	—	47	—	47
Fixed Income	—	101	—	101
Real Estate	—	7	11	18
Private Equity	—	—	4	4
Total	$ 1	$229	$ 15	$245

Level 1 cash equivalents are based on observable market prices and are comprised of the fair value of commercial paper, money market funds, and certificates of deposit.

Level 2 investments comprise amounts held in commingled equity funds, United States bond funds, and real estate funds. Valuations are based on active market quoted prices for assets held by each respective fund.

Level 3 real estate investments were valued using a real estate index value. The real estate index value was developed based on appraisals comprising 87% of real estate assets tracked by the index in 2012 and comprising 85% in 2011.

Level 3 private equity funds are classified as funds-of-funds. They are valued based on individual fund manager valuation models.

The tables above reflecting the fair value measurements of pension plan assets include Level 2 assets for the UES pension plan of $14 million at December 31, 2012, and $10 million at December 31, 2011.

The following tables set forth a reconciliation of changes in the fair value of pension assets classified as Level 3 in the fair value hierarchy. There were no transfers in or out of Level 3.

	Year Ended December 31, 2012		
	Private Equity	Real Estate	Total
Beginning Balance at January 1, 2012	$4	$ 11	$15
Actual Return on Plan Assets:			
Assets Held at Reporting Date	1	2	3
Purchases, Sales, and Settlements	1	—	1
Ending Balance at December 31, 2012	$6	$ 13	$19

	Year Ended December 31, 2011		
	Private Equity	Real Estate	Total
Beginning Balance at January 1, 2011	$ 2	$ 10	$12
Actual Return on Plan Assets:			
Assets Held at Reporting Date	—	1	1
Purchases, Sales, and Settlements	2	—	2
Ending Balance at December 31, 2011	$ 4	$ 11	$15

UNS Gas and UNS Electric have no pension assets classified as Level 3 in the fair value hierarchy.

Pension Plan Investments

Investment Goals

Asset allocation is the principal method for achieving each pension plan's investment objectives, while maintaining an appropriate level of risk. We will consider the projected impact on benefit security of any proposed changes to the current asset allocation policy. The expected long-term returns and implications for pension plan sponsor funding will be reviewed in selecting policies to ensure that current asset pools are projected to be adequate to meet the expected liabilities of the pension plans. We expect to use asset allocation policies weighted most heavily to equity and fixed income funds, while maintaining some exposure to real estate and opportunistic funds. Within the fixed income allocation, long-duration funds may be used to partially hedge interest rate risk.

Risk Management

We recognize the difficulty of achieving investment objectives in light of the uncertainties and complexities of the investment markets. We also recognize some risk must be assumed to achieve a pension plan's long-term investment objectives. In establishing risk tolerances, the following factors affecting risk tolerance and risk objectives will be considered: plan status, plan sponsor financial status and profitability, plan features, and workforce characteristics. We have determined that the pension plans can tolerate some interim fluctuations in market value and rates of return in order to achieve long-term objectives. TEP tracks each pension plan's portfolio relative to the benchmark through quarterly investment reviews. The reviews consist of a performance and risk assessment of all investment categories and on the portfolio as a whole. Investment managers for the pension plan may use derivative financial instruments for risk management purposes or as part of their investment strategy. Currency hedges may also be used for defensive purposes.

Relationship between Plan Assets and Benefit Obligations

The overall health of each plan will be monitored by comparing the value of plan obligations (both Accumulated Benefit Obligation and Projected Benefit Obligation) against the fair value of assets and tracking the changes in each. The frequency of this monitoring will depend on the availability of plan data, but will be no less frequent than annually via annual actuarial valuation.

Target Allocation Percentages

The current target allocation percentages for the major asset categories of the plan as of December 31, 2012, follow. Each plan allows a variance of +/- 2% from these targets before funds are automatically rebalanced.

	TEP Plan	UES Plan	VEBA Trust
Fixed Income	41%	33%	35%
United States Large Cap	24	28	43
Non-United States Developed	15	17	13
Real Estate	8	11	—
United States Small Cap	5	6	2
Non-United States Emerging	5	5	5
Private Equity	2	—	—
Cash/Treasury Bills	—	—	2
Total	100%	100%	100%

Pension Fund Descriptions

For each type of asset category selected by the Pension Committee, our investment consultant assembles a group of third-party fund managers and allocates a portion of the total investment to each fund manager. In the case of the private equity fund, our investment consultant directs investments to a private equity manager that invests in third-parties' funds.

Other Retiree Benefit Assets

As of December 31, 2012, the fair value of VEBA trust assets was $7 million, of which $3 million were fixed income investments and $4 million were equities. As of December 31, 2011, the fair value of VEBA trust assets was $5 million, including $3 million of fixed income investments and approximately $2 million of equity and money market funds. The VEBA trust assets are primarily Level 2. There are no Level 3 assets in the VEBA trust.

ESTIMATED FUTURE BENEFIT PAYMENTS

TEP expects the following benefit payments to be made by the defined benefit pension plans and retiree plan, which reflect future service, as appropriate.

	Pension Benefits	Other Retiree Benefits
	-Millions of Dollars-	
2013	$ 15	$ 4
2014	16	5
2015	16	5
2016	18	5
2017	20	5
Years 2018-2022	110	30

TEP's union plan was amended in 2012 to allow terminated participants to elect early retirement benefits equal to the actuarial equivalent of the participant's termination retirement benefit. The impact of the amendment on estimated future benefit payments shown above was approximately $5 million in total. The pension benefit obligation was not materially affected by this amendment.

UNS Gas and UNS Electric expect annual benefit payments, made by the defined benefit pension and retiree plans, to be approximately $2 million in 2013 through 2017, and $9 million in 2018 through 2022.

DEFINED CONTRIBUTION PLAN

We offer a defined contribution savings plan to all eligible employees. The Internal Revenue Code identifies the plan as a qualified 401(k) plan. Participants direct the investment of contributions to certain funds in their account which may include a UNS Energy stock fund. We match part of a participant's contributions to the plan. TEP made matching contributions to the plan of $5 million in 2012, $5 million in 2011, and $4 million in 2010. UNS Gas and UNS Electric made matching contributions of less than $1 million in each of 2012, 2011, and 2010.

NOTE 10. SHARE-BASED COMPENSATION PLAN

Under the UNS Energy 2011 Omnibus Stock and Incentive Plan (2011 Plan), the Compensation Committee of the UNS Energy Board of Directors (Compensation Committee) may issue various types of share-based compensation, including stock options, restricted shares/units, and performance shares. The total number of shares which may be awarded under the 2011 Plan cannot exceed 1.2 million shares.

STOCK OPTIONS

Stock options are granted with an exercise price equal to the fair market value of the stock on the date of grant, vest over three years, become exercisable in one-third increments on each anniversary date of the grant, and expire on the tenth anniversary of the grant. Compensation expense is recorded on a straight-line basis over the service period for the total award based on the grant date fair value of the options less estimated forfeitures. For awards granted to retirement-eligible officers, compensation expense is recorded immediately.

See summary of the stock option activity in the table below:

(Shares in Thousands)	2012		2011		2010	
Stock Options	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding, Beginning of Year	581	$29.11	921	$27.96	1,598	$24.50
Granted	—	—	—	—	—	—
Exercised	(132)	26.54	(319)	25.60	(660)	19.33
Forfeited/Expired	(40)	37.88	(21)	31.92	(17)	37.88
Outstanding, End of Year	409	29.09	581	29.11	921	27.96
Exercisable, End of Year	409	$29.09	508	$29.53	654	$28.70
Aggregate Intrinsic Value of Options Exercised ($000s)		$1,878		$3,690		$9,124

	At December 31, 2012
Aggregate Intrinsic Value for Options Outstanding ($000s)	$ 5,450
Aggregate Intrinsic Value for Options Exercisable ($000s)	$ 5,450
Weighted Average Remaining Contractual Life of Outstanding Options	5.2 years
Weighted Average Remaining Contractual Life of Exercisable Options	5.2 years

See summary of stock options in the table below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Shares (000s)	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Shares (000s)	Weighted Average Exercise Price
$26.11—$37.88	409	5.2 years	$29.09	409	$29.09

RESTRICTED STOCK UNITS AND PERFORMANCE SHARE AWARDS

Restricted Stock Units

Restricted stock and stock units are generally granted to non-employee directors. Restricted stock is an award of Common Stock that is subject to forfeiture if the restrictions specified in the award are not satisfied. Stock units are a non-voting unit of measure that is equivalent to one share of Common Stock. The directors may elect to receive stock units in lieu of restricted stock. Restricted stock generally vests over periods ranging from one to three years and is payable in Common Stock. Stock units vest either immediately or over periods ranging from one to three years. The restricted stock units vest immediately upon death, disability, or retirement. In the January following the year the person is no longer a director, Common Stock shares will be issued for the vested stock units. Compensation expense equal to the fair market value on the grant date is recognized over the vesting period. Fully vested but undistributed stock unit awards accrue dividend equivalent stock units based on the fair market value of common shares on the date the dividend is paid.

Common Stock shares totaling 31,058 in 2012, 56,705 in 2011, and 14,866 in 2010 were issued with no additional increase in equity as the expense was previously recognized over the vesting period.

The Compensation Committee granted in total, the following stock units to non-employee directors:

- 2012—15,303 stock units at a weighted average fair value of $35.94 per share;
- 2011—14,655 stock units at a weighted average fair value of $37.53 per share; and
- 2010—15,620 stock units at a weighted average fair value of $31.69 per share.

Performance Share Awards

In 2012, 2011, and 2010, the Compensation Committee granted performance share awards to upper management. Half of the performance share awards will be paid out in Common Stock based on a comparison of UNS Energy's cumulative Total Shareholder Return to the Edison Electric Institute Index during the performance period. The grant date fair value of these awards with a market condition were derived based on a Monte Carlo simulation. Compensation expense equal to the fair value on the grant date is recognized over the vesting period if the requisite service period is fulfilled, whether or not the threshold is achieved. The remaining half will be paid out in Common Stock based on cumulative net income during the performance period. The grant date fair values of these awards with a performance condition were the closing Common Stock market prices on the dates of grant. Compensation expense equal to the fair value on the grant date is recognized over the requisite service period only for the awards that ultimately vest. The performance shares vest based on the achievement of these goals by the end of the performance period; any unearned awards are forfeited. Vested performance shares are eligible for dividend equivalents during the performance period.

			Grant Date Fair Value	
Award Year	Performance Period	Shares Granted	Market Condition	Performance Condition
2012	January 1, 2012 to December 31, 2014	80,140	$32.71	$36.40
2011	January 1, 2011 to December 31, 2013	80,440	33.73	36.58
2010	January 1, 2010 to December 31, 2012	93,720	31.26	30.52

At December 31, 2012, upon completion of the three-year performance period, 76,478 shares were earned and vested; 17,242 shares were unearned and forfeited. The vested performance shares also earned 10,516 in dividend equivalent shares.

	Performance Shares		Restricted Stock Units	
	Shares (000s)	Weighted Average Grant Date Fair Value	Shares (000s)	Weighted Average Grant Date Fair Value
Non-vested at January 1, 2012	153	$32.85	15	$37.53
Granted	80	34.56	15	35.94
Vested	(77)	31.08	(15)	37.53
Forfeited	(11)	31.42	—	—
Non-vested at December 31, 2012	145	34.83	15	35.94

SHARE-BASED COMPENSATION EXPENSE (Stock Options, Restricted Stock Units, and Performance Shares)

Annually during 2010 through 2012, UNS Energy recorded share-based compensation expense of $3 million, $2 million of which related to TEP. No share-based compensation was capitalized as part of the cost of an asset. The actual tax deduction realized from the exercise of share-based payment arrangements totaled less than $1 million in 2012 and $3 million in 2010. UNS Energy did not realize a tax deduction from the exercise of share-based payment arrangements in 2011.

At December 31, 2012, the total unrecognized compensation cost related to non-vested share-based compensation was $2 million, which will be recorded as compensation expense over the remaining vesting periods through December 2014. The total number of shares awarded but not yet issued, including target performance based shares, under the share-based compensation plans at December 31, 2012, was 1 million.

NOTE 11. FAIR VALUE MEASUREMENTS

We categorize our assets and liabilities at fair value into the three-level hierarchy based on inputs used to determine the fair value measurement. Level 1 inputs are unadjusted quoted prices for identical assets or liabilities in an active market. Level 2 inputs include quoted prices for similar assets or liabilities, quoted prices in non-active markets, and pricing models whose inputs are observable. Level 3 inputs are unobservable and supported by little or no market activity.

The following tables present, by level within the fair value hierarchy, UNS Energy's and TEP's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified in their entirety based on the lowest level of input significant to the fair value measurement. There were no transfers between Levels 1, 2, or 3 for either reporting period.

	UNS Energy			
	Level 1	**Level 2**	**Level 3**	**Total**
	December 31, 2012 - Millions of Dollars -			
Assets				
Cash Equivalents(1)	$ 20	$—	$—	$ 20
Rabbi Trust Investments to Support the Deferred Compensation and SERP Plans(2)	—	19	—	19
Energy Contracts(3)	—	2	5	7
Total Assets	20	21	5	46
Liabilities				
Energy Contracts(3)	—	(7)	(10)	(17)
Interest Rate Swaps(4)	—	(10)	—	(10)
Total Liabilities	—	(17)	(10)	(27)
Net Total Assets and (Liabilities)	$ 20	$ 4	$ (5)	$ 19

	UNS Energy			
	Level 1	**Level 2**	**Level 3**	**Total**
	December 31, 2011 - Millions of Dollars -			
Assets				
Cash Equivalents(1)	$ 23	$—	$—	$ 23
Rabbi Trust Investments to Support the Deferred Compensation and SERP Plans(2)	—	16	—	16
Energy Contracts(3)	—	—	14	14
Total Assets	23	16	14	53
Liabilities				
Energy Contracts(3)	—	(21)	(24)	(45)
Interest Rate Swaps(4)	—	(12)	—	(12)
Total Liabilities	—	(33)	(24)	(57)
Net Total Assets and (Liabilities)	$ 23	$ (17)	$ (10)	$ (4)

	TEP			
	Level 1	**Level 2**	**Level 3**	**Total**
	December 31, 2012 - Millions of Dollars -			
Assets				
Cash Equivalents(1)	$ 7	$—	$—	$ 7
Rabbi Trust Investments to Support the Deferred Compensation and SERP Plans(2)	—	19	—	19
Energy Contracts(3)	—	1	2	3
Total Assets	7	20	2	29
Liabilities				
Energy Contracts(3)	—	(3)	(2)	(5)
Interest Rate Swaps(4)	—	(10)	—	(10)
Total Liabilities	—	(13)	(2)	(15)
Net Total Assets and (Liabilities)	$ 7	$ 7	$—	$ 14

	TEP			
	Level 1	Level 2	Level 3	Total
	December 31, 2011 - Millions of Dollars -			
Assets				
Cash Equivalents[1]	$ 8	$—	$—	$ 8
Rabbi Trust Investments to Support the Deferred Compensation and SERP Plans[2]	—	16	—	16
Energy Contracts[3]	—	—	3	3
Total Assets	8	16	3	27
Liabilities				
Energy Contracts[3]	—	(9)	(3)	(12)
Interest Rate Swaps[4]	—	(11)	—	(11)
Total Liabilities	—	(20)	(3)	(23)
Net Total Assets and (Liabilities)	$ 8	$ (4)	$—	$ 4

(1) Cash Equivalents are based on observable market prices and include the fair value of money market funds and certificates of deposit. These amounts are included in Cash and Cash Equivalents and in Investments and Other Property—Other on the balance sheets.

(2) Rabbi Trust Investments include amounts held in mutual and money market funds related to deferred compensation and SERP benefits. The valuation is based on quoted prices traded in active markets. These investments are included in Investments and Other Property – Other on the balance sheets.

(3) Energy Contracts include gas swap agreements (Level 2), gas and power options (Level 3), forward power purchase and sales contracts (Level 3), and forward power purchase contracts indexed to gas (Level 3), entered into to reduce exposure to energy price risk. These contracts are included in Other Assets and Derivative Instruments on the balance sheets. The valuation techniques are described below. See Note 16.

(4) Interest Rate Swaps are valued based on the 3-month or 6-month LIBOR index or the Securities Industry and Financial Markets Association municipal swap index. These interest rate swaps are included in Derivative Instruments on the balance sheets.

Energy Contracts

We primarily apply the market approach for recurring fair value measurements. When we have observable inputs for substantially the full term of the asset or liability, such as gas swap derivatives valued using New York Mercantile Exchange pricing adjusted for basis differences, we categorize the instrument in Level 2. We categorize derivatives in Level 3 when we use an aggregate pricing service or published prices that represent a consensus reporting of multiple brokers.

For both power and gas prices, we obtain quotes from brokers, major market participants, exchanges, or industry publications, and rely on our own price experience from active transactions in the market. We primarily use one set of quotations each for power and for gas and then validate those prices using other sources. We believe that the market information provided is reflective of market conditions as of the time and date indicated.

Published prices for energy derivative contracts may not be available due to the nature of contract delivery terms such as non-standard time blocks and non-standard delivery points. In these cases, we apply adjustments based on historical price curve relationships, transmission, and line losses.

We estimate the fair value of our options using the Black-Scholes-Merton option pricing model which includes inputs such as implied volatility, correlations, interest rates, and forward price curves.

We also consider the impact of counterparty credit risk using current and historical default and recovery rates, as well as our own credit risk using credit default swap data.

Our assessments of the significance of a particular input to the fair value measurements requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. We review the assumptions underlying our contracts monthly.

The following table provides quantitative information regarding significant unobservable inputs in UNS Energy's Level 3 fair value measurements:

	Fair Value at December 31, 2012		Range of Unobservable Input
	Assets	Liabilities	
	-Millions of Dollars-		
Forward Contracts(1)	$4	$ (10)	
Valuation Technique: Market approach			
Unobservable Input:			
Market price per MWh			$19.50 - $ 56.24
Option Contracts(2)	1	—	
Valuation Technique: Option model			
Unobservable Inputs:			
Market Price per MWh			$29.50 - $ 46.00
Power Volatility			30.38% - 59.95%
Market Price per MMbtu			$3.22 - $ 3.84
Gas Volatility			29.32% -36.14%
Level 3 Energy Contracts	$5	$ (10)	

(1) TEP comprises $1 million of the forward contract assets and $2 million of the forward contract liabilities.

(2) The option contracts relate to TEP.

Our exposure to risk resulting from changes in the unobservable inputs identified above is mitigated as we report the change in fair value of energy contract derivatives as a regulatory asset or a regulatory liability. These are recoverable through the PPFAC or PGA mechanisms, or as a component of other comprehensive income, rather than in the income statements.

The following tables present a reconciliation of changes in the fair value of assets and liabilities classified as Level 3 in the fair value hierarchy:

	Year Ended December 31, 2012	
	UNS Energy	TEP
	Energy Contracts	
	-Millions of Dollars-	
Balance as of December 31, 2011	$(10)	$—
Realized/Unrealized Gains/(Losses)Recorded to:		
Net Regulatory Assets/Liabilities – Derivative Instruments	(5)	1
Settlements	10	(1)
Balance as of December 31, 2012	$ (5)	$—
Total Gains/(Losses) Attributable to the Change in Unrealized Gains/(Losses) Relating to Assets/Liabilities Still Held at the End of the Period	$ (1)	$—

	Year Ended December 31, 2011	
	UNS Energy	TEP
	Energy Contracts	
	-Millions of Dollars-	
Balance as of December 31, 2010	$(10)	$ 1
Realized/Unrealized Gains/(Losses) Recorded to:		
Net Regulatory Assets/Liabilities – Derivative Instruments	(9)	2
Other Comprehensive Income	(1)	(1)
Settlements	10	(2)
Balance as of December 31, 2011	$(10)	$—
Total Gains/(Losses) Attributable to the Change in Unrealized Gains/(Losses) Relating to Assets/Liabilities Still Held at the End of the Period	$ (9)	$—

Financial Instruments Not Carried at Fair Value

The fair value of a financial instrument is the market price to sell an asset or transfer a liability at the measurement date. We use the following methods and assumptions for estimating the fair value of our financial instruments:

- The carrying amounts of our current assets and liabilities, including current maturities of long-term debt, and amounts outstanding under our credit agreements, which approximate the fair values due to the short-term nature of these financial instruments. These items have been excluded from the table below.
- For Investment in Lease Debt, we calculate the present value of remaining cash flows using current market rates for instruments with similar characteristics such as credit rating and time-to-maturity. We also incorporate the impact of counterparty credit risk using market credit default swap data.
- For Investment in Lease Equity, we estimate the price at which an investor would realize a target internal rate of return. Our estimates include: the mix of debt and equity an investor would use to finance the purchase; the cost of debt; the required return on equity; and income tax rates. The estimate assumes a residual value based on an appraisal of Springerville Unit 1 in 2011.
- For Long-Term Debt, we use quoted market prices, where available, or calculate the present value of remaining cash flows at the balance sheet date. When calculating present value, we use current market rates for bonds with similar characteristics such as credit rating and time-to-maturity. We consider the principal amounts of variable rate debt outstanding to be reasonable estimates of the fair value. We also incorporate the impact of our own credit risk using a credit default swap rate.

The use of different estimation methods and/or market assumptions may yield different estimated fair value amounts. The carrying value recorded on the balance sheet and the estimated fair values of our financial instruments were as follows:

		December 31,			
		2012		**2011**	
	Fair Value Hierarchy	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
		-Millions of Dollars-			
Assets:					
TEP Investment in Lease Debt	Level 2	$ 9	$ 9	$ 29	$ 29
TEP Investment in Lease Equity	Level 3	36	23	37	21
Liabilities:					
Long-Term Debt					
UNS Energy	Level 2	1,498	1,583	1,517	1,543
TEP	Level 2	1,223	1,271	1,080	1,061

TEP held the Investment in Lease Debt to maturity in January 2013. This investment was stated at amortized cost, which means the purchase cost had been adjusted for the amortization of the premium and discount to maturity.

The fair value of TEP's Long-Term Debt increased from prior year because of a change in valuation methodology concerning the make-whole premium applied to the bonds if they are called early.

NOTE 12. UNS ENERGY EARNINGS PER SHARE

We compute basic Earnings Per Share (EPS) by dividing Net Income by the weighted average number of common shares outstanding during the period. Except when the effect would be anti-dilutive, the diluted EPS calculation includes the impact of shares that could be issued upon exercise of outstanding stock options; contingently issuable shares under equity-based awards, or common shares that would result from the conversion of Convertible Senior Notes. The numerator in calculating diluted EPS is Net Income adjusted for the interest on Convertible Senior Notes (net of tax) that would not be paid if the remaining notes, not yet converted, were converted to Common Stock.

The following table shows the effects of potentially dilutive common stock on the weighted average number of shares:

	Years Ended December 31, 2012	2011	2010
	-Thousands of Dollars-		
Numerator:			
Net Income	$90,919	$109,975	$112,984
Income from Assumed Conversion of Convertible Senior Notes	1,100	4,390	4,390
Adjusted Numerator	$92,019	$114,365	$117,374
	-Thousands of Shares-		
Denominator:			
Weighted Average Shares of Common Stock Outstanding:			
Common Shares Issued	40,212	36,780	36,200
Fully Vested Deferred Stock Units	150	129	123
Participating Securities	—	53	92
Total Weighted Average Shares of Common Stock Outstanding and Participating Securities—Basic	40,362	36,962	36,415
Effect of Diluted Securities:			
Convertible Senior Notes	1,062	4,281	4,178
Options and Stock Issuable Under Share-Based Compensation Plans	331	366	448
Total Shares—Diluted	41,755	41,609	41,041

The following table shows the number of stock options excluded from the diluted EPS computation because the stock option's exercise price was greater than the average market price of the Common Stock:

	Years Ended December 31, 2012	2011	2010
	-Thousands of Shares-		
Stock Options Excluded from the Diluted EPS Computation	50	153	212

In the first half of 2012, the entire balance of Convertible Senior Notes was converted to Common Shares or redeemed for cash. See Note 6.

NOTE 13. MILLENNIUM INVESTMENTS

In 2010, Millennium recorded impairment losses of $10 million reducing the book value of its unconsolidated equity and cost method investments to zero. Millennium received notification of valuation changes and ownership percentage reductions as projects lost viability and funding failed. In addition, Millennium sold a wholly-owned subsidiary and recorded a gain of less than $1 million. Gains and losses were included in Other Income or Other Expense in UNS Energy's income statements. Millennium also wrote off $3 million of Deferred Tax Assets related to its investments.

In 2009, Millennium sold an equity investment, receiving an upfront payment of $5 million in 2009 and a $15 million, 6% secured promissory note. Millennium received the remaining principal amount of $15 million in 2012.

NOTE 14. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

The following recently issued accounting standards are not yet reflected in the financial statements:

- The Financial Accounting Standards Board (FASB) issued a pronouncement that will require entities to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position (balance sheet) or subject to an agreement similar to a master netting arrangement. In addition, the pronouncement requires disclosure of collateral received and posted in connection with master netting arrangements. We will be required to comply in the first quarter of 2013 and do not expect this pronouncement to have a material impact on our disclosures.
- The FASB issued a rule which amends the guidance for impairment testing of indefinite-lived intangible assets. An entity will have the option to perform qualitative analysis to determine whether an indefinite-lived intangible asset may be impaired. If the qualitative assessment does not result in likely impairment, an entity will not be required to perform the quantitative impairment test. We will be required to comply in the first quarter of 2013; however, we do not expect this pronouncement to have a material impact on our financial statements as our indefinite-lived intangible assets, RECs, are currently recoverable under the RES as we use RECs to comply with renewable resources requirements.

- The FASB decided in December 2012 to require new disclosures on items reclassified from AOCI. Companies will be required to disclose, in a single location, amounts reclassified from each component of AOCI based on its source and the income statement line items affected by the reclassification. We plan to present this information in a footnote. We will be required to comply in the first quarter of 2013 and do not expect this decision to have a material impact on our financial statements.

NOTE 15. SUPPLEMENTAL CASH FLOW INFORMATION

A reconciliation of net income to net cash flows from operating activities follows:

	UNS Energy		
	Years Ended December 31,		
	2012	2011	2010
	-Thousands of Dollars-		
Net Income	$ 90,919	$109,975	$112,984
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities			
Depreciation Expense	141,303	133,832	128,215
Amortization Expense	35,784	30,983	28,094
Depreciation and Amortization Recorded to Fuel and O&M Expense	6,622	6,140	5,432
Amortization of Deferred Debt-Related Costs included in Interest Expense	3,000	3,985	3,753
Provision for Retail Customer Bad Debts	2,767	2,072	3,724
Use of Renewable Energy Credits for Compliance	5,935	5,695	4,745
Deferred Income Taxes	60,273	75,787	28,142
Deferred Tax Valuation Allowance	(9)	(272)	7,510
Pension and Retiree Expense	21,856	21,202	19,688
Pension and Retiree Funding	(29,058)	(28,775)	(27,742)
Share-Based Compensation Expense	2,573	2,599	2,751
Excess Tax Benefit from Stock Options Exercised	(145)	—	(3,338)
Allowance for Equity Funds Used During Construction	(3,464)	(4,496)	(4,232)
Increase (Decrease) to Reflect PPFAC/PGA Recovery	32,246	(4,932)	(29,622)
Competition Transition Charge Revenue Refunded	—	(35,958)	(10,095)
Partial Write-off of Tucson to Nogales Transmission Line	4,668	—	—
Liquidated Damages for Springerville Unit 3 Outage	2,050	—	—
Gain on Settlement of El Paso Electric Dispute	—	(7,391)	—
Loss on Millennium's Investments	—	—	9,936
Changes in Assets and Liabilities which Provided (Used)			
Cash Exclusive of Changes Shown Separately			
Accounts Receivable	3,369	2,743	(8,851)
Materials and Fuel Inventory	(39,429)	(20,864)	21,744
Accounts Payable	595	8,792	2,661
Income Taxes	(11,557)	(2,739)	24,470
Interest Accrued	6,922	14,344	14,354
Taxes Other Than Income Taxes	(58)	2,857	2,442
Current Regulatory Liabilities	(684)	2,644	2,788
Other	11,631	19,097	7,367
Net Cash Flows – Operating Activities	$348,109	$337,320	$346,920

	TEP		
	Years Ended December 31,		
	2012	2011	2010
	-Thousands of Dollars-		
Net Income	$ 65,470	$ 85,334	$108,260
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities			
Depreciation Expense	110,931	104,894	99,510
Amortization Expense	39,493	34,650	32,196
Depreciation and Amortization Recorded to Fuel and O&M Expense	5,384	4,509	3,855
Amortization of Deferred Debt-Related Costs included in Interest Expense	2,227	2,378	2,146
Provision for Retail Customer Bad Debts	1,871	1,447	2,506
Use of Renewable Energy Credits for Compliance	5,071	5,190	4,245
Deferred Income Taxes	45,232	59,309	24,897
Pension and Retiree Expense	19,289	18,816	17,454
Pension and Retiree Funding	(25,899)	(25,878)	(25,672)
Share-Based Compensation Expense	2,029	2,027	2,131
Allowance for Equity Funds Used During Construction	(2,840)	(3,842)	(3,567)
Increase (Decrease) to Reflect PPFAC Recovery	31,113	(6,165)	(21,541)
Competition Transition Charge Revenue Refunded	—	(35,958)	(10,095)
Partial Write-off of Tucson to Nogales Transmission Line	4,484	—	—
Liquidated Damages for Springerville Unit 3 Outage	2,050	—	—
Gain on Settlement of El Paso Electric Dispute	—	(7,391)	—
Changes in Assets and Liabilities which Provided (Used)			
Cash Exclusive of Changes Shown Separately			
Accounts Receivable	(871)	4,809	(5,156)
Materials and Fuel Inventory	(38,384)	(19,789)	20,920
Accounts Payable	1,115	14,561	(447)
Income Taxes	(11,421)	(5,582)	20,203
Interest Accrued	8,055	14,268	14,431
Taxes Other Than Income Taxes	905	2,282	1,469
Current Regulatory Liabilities	(3,040)	303	2,500
Other	5,655	18,122	12,238
Net Cash Flows – Operating Activities	$267,919	$268,294	$302,483

Non-Cash Transactions

In 2012, the following non-cash transactions occurred:

- UNS Energy converted $147 million of the previously outstanding $150 million Convertible Senior Notes into Common Shares. See Note 6; and
- TEP redeemed $193 million of tax-exempt bonds and reissued debt using a trustee. Since the cash flowed through trust accounts, the redemption and reissuance of debt resulted in a non-cash transaction at TEP. See Note 6.

In 2010, the following non-cash transactions occurred:

- TEP used a trustee to issue and redeem $37 million tax-exempt bonds. TEP had no cash receipts or payments as a result of this transaction. See Note 6; and
- TEP deposited proceeds from the issuance of $100 million Pima County tax-exempt IDBs in a construction fund with a trustee. TEP drew down funds as qualified expenditures were incurred. The $11 million remaining in the construction fund at December 31, 2010, affected recognized assets and liabilities but did not result in cash receipts or payments. TEP drew down the remaining funds in the construction fund by March 2011. See Note 6.

Other non-cash investing and financing activities that affected recognized assets and liabilities but did not result in cash receipts or payments were as follows:

	Years Ended December 31,		
	2012	2011	2010
	-Thousands of Dollars-		
(Decrease)/Increase to Utility Plant Accruals(1)	$ 4,813	$ (2,741)	$ 8,514
Net Cost of Removal of Interim Retirements(2)	35,983	31,626	4,592
Capital Lease Obligations(3)	11,967	15,162	16,630
Asset Retirement Obligations(4)	789	7,638	(1,872)
UED Secured Term Loan Prepayments(5)	—	—	3,188

(1) The non-cash additions to Utility Plant represent accruals for capital expenditures.

(2) The non-cash net cost of removal of interim retirements represents an accrual for future asset retirement obligations that does not impact earnings.

(3) The non-cash change in capital lease obligations represents interest accrued for accounting purposes in excess of interest payments.

(4) The non-cash additions to asset retirement obligations and related capitalized assets represent revision of estimated asset retirement cost due to changes in timing and amount of expected future asset retirement obligations.

(5) The non-cash UED Secured Term Loan prepayment represents deposits applied to $30 million of loan principal.

NOTE 16. ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

See Note 1 for description of our related accounting policies and Note 11 for information related to the fair value of derivatives.

FINANCIAL IMPACT OF DERIVATIVES

Cash Flow Hedges

UNS Energy and TEP had liabilities related to cash flow hedges of $12 million as of December 31, 2012, and $14 million as of December 31, 2011. TEP's power purchase swap agreement under which these hedges are entered into expires in 2015.

The after-tax unrealized gains and losses on cash flow hedge activity and amounts reclassified to earnings are reported in the statements of other comprehensive income. The amounts reclassified to earnings are reported in Long Term Debt Interest Expense, Capital Leases Interest Expense, and Purchased Power Expense in the statements of income. The amounts expected to be reclassified to earnings within the next twelve months is estimated to be $2 million.

Regulatory Treatment of Commodity Derivatives

We disclose unrealized gains and losses on energy contracts that are recoverable through the PPFAC or PGA on the balance sheets as a regulatory asset or a regulatory liability rather than in the statements of other comprehensive income or in the income statements, as shown in the following table:

	UNS Energy			TEP		
	Years Ended December 31,					
	2012	2011	2010	2012	2011	2010
	-Millions of Dollars-					
Increase (Decrease) to Regulatory Assets /Liabilities	$(21)	$2	$—	$(6)	$2	$(4)

The fair values of derivative assets and liabilities were as follows:

	UNS Energy		TEP	
	Years Ended December 31,			
	2012	2011	2012	2011
	-Millions of Dollars-			
Assets	$ 7	$ 14	$ 4	$ 3
Liabilities	(15)	(43)	(4)	(9)
Net Assets (Liabilities)	$ (8)	$(29)	$—	$(6)

Derivative assets are included in Derivative Instruments and Other Non-Current Assets on the UNS Energy balance sheet and Other Current Assets and Other Non-Current Assets on the TEP balance sheet.

The realized losses on settled gas swaps that are fully recoverable through the PPFAC or PGA were as follows:

	UNS Energy			TEP		
	Years Ended December 31,					
	2012	2011	2010	2012	2011	2010
	-Millions of Dollars-					
Realized Losses on Gas Swaps	$(22)	$(19)	$(23)	$(10)	$(7)	$(9)

At December 31, 2012, UNS Energy and TEP had contracts that will settle through the fourth quarter of 2015.

Other Commodity Derivatives

The settlement of forward purchased power and sales contracts that do not result in physical delivery were reflected in the financial statements of UNS Energy and TEP as follows:

	UNS Energy			TEP		
	2012	2011	2010	2012	2011	2010
	-Millions of Dollars-					
Recorded in Wholesale Sales [(1)]:						
Forward Power Sales	$ 22	$ 41	$ 53	$ 5	$ 14	$ 27
Forward Power Purchases	(20)	(46)	(62)	(6)	(15)	(34)
Total Sales and Purchases Not Resulting in Physical Delivery	$ 2	$ (5)	$ (9)	$(1)	$ (1)	$ (7)

(1) The amounts previously reported have been revised.

DERIVATIVE VOLUMES

At December 31, 2012, UNS Energy had gas swaps totaling 14,351 billion British thermal units (GBtu) and power contracts totaling 2,228 Gigawatt-hours (GWh), while TEP had gas swaps totaling 6,158 GBtu and power contracts totaling 820 GWh. At December 31, 2011, UNS Energy had gas swaps totaling 14,856 GBtu and power contracts totaling 3,147 GWh, while TEP had gas swaps totaling 6,855 GBtu and power contracts totaling 815 GWh.

CREDIT RISK ADJUSTMENT

When the fair value of our derivative contracts is reflected as an asset, the counterparty owes us and this creates credit risk. We also consider the impact of our own credit risk on instruments that are in a net liability position. The impact of counterparty credit risk and our own credit risk on the fair value of derivative asset contracts was less than $0.5 million at December 31, 2012 and December 31, 2011.

CONCENTRATION OF CREDIT RISK

The use of contractual arrangements to manage the risks associated with changes in energy commodity prices creates credit risk exposure resulting from the possibility of non-performance by counterparties pursuant to the terms of their contractual obligations. We enter into contracts for the physical delivery of energy and gas which contain remedies in the event of non-performance by the supply counterparties. In addition, volatile energy prices can create significant credit exposure from energy market receivables and subsequent measurement at fair value valuations.

We have contractual agreements for energy procurement and hedging activities that contain certain provisions requiring each company to post collateral under certain circumstances. These circumstances include: exposures in excess of unsecured credit limits provided to TEP, UNS Gas, or UNS Electric; credit rating downgrades; or a failure to meet certain financial ratios. In the event that such credit events were to occur, we would have to provide certain credit enhancements in the form of cash or LOCs to fully collateralize our exposure to these counterparties.

The following table shows the sum of the fair value of all derivative instruments under contracts with credit-risk related contingent features that are in a net liability position at December 31, 2012. It also shows LOCs posted and additional collateral to be posted if credit-risk related contingent features are triggered.

	UNS Energy	TEP
	December 31, 2012	
	-Millions of Dollars-	
Net Liability Position	$36	$10
LOCs	1	1
Additional Collateral to Post if Contingent Features Triggered	36	10

As of December 31, 2012, TEP had $15 million of credit exposure to other counterparties' creditworthiness related to its wholesale marketing and gas hedging activities, of which two counterparties individually composed greater than 10% of the total credit exposure. UNS Electric and UNS Gas had less than $1 million of such credit exposure related to its supply and hedging contracts.

NOTE 17. QUARTERLY FINANCIAL DATA (UNAUDITED)

Our quarterly financial information is unaudited but, in management's opinion, includes all adjustments necessary for a fair presentation. Our utility businesses are seasonal in nature. Peak sales periods for TEP and UNS Electric generally occur during the summer while UNS Gas' sales generally peak during the winter. Accordingly, comparisons among quarters of a year may not represent overall trends and changes in operations.

	UNS Energy			
	First	Second	Third	Fourth
	-Thousands of Dollars- (Except Per Share Amounts)			
2012				
Operating Revenue	$315,387	$363,997	$434,108	$348,274
Operating Income	34,403	68,065	106,409	42,918
Net Income	6,476	26,273	50,664	7,506
Basic EPS	0.17	0.65	1.22	0.18
Diluted EPS	0.17	0.64	1.21	0.18
2011				
Operating Revenue	$338,177	$365,141	$441,557	$333,827
Operating Income	44,820	71,290	123,760	41,837
Net Income	13,472	28,604	59,712	8,187
Basic EPS	0.37	0.77	1.61	0.22
Diluted EPS	0.35	0.71	1.46	0.22

EPS is computed independently for each of the quarters presented. Therefore, the sum of the quarterly EPS amounts may not equal the total for the year.

	TEP			
	First	Second	Third	Fourth
	-Thousands of Dollars-			
2012				
Operating Revenue	$223,978	$299,419	$366,910	$271,353
Operating Income	17,892	58,211	94,079	30,305
Net Income (Loss)	(1,461)	21,910	44,569	452
2011				
Operating Revenue	$239,588	$295,233	$369,845	$251,720
Operating Income	27,792	62,497	111,479	27,640
Net Income	4,704	25,158	53,912	1,560

The following tables reflect the quarterly impact of revisions on UNS Energy's statements of income recorded in the fourth quarter of 2012 (See Note 1):

	UNS Energy					
	2012 Three Months Ended					
	March 31,		June 30,		September 30,	
	As Reported	As Revised	As Reported	As Revised	As Reported	As Revised
	-Thousands of Dollars-					
Income Statement						
Operating Revenue	$318,874	$315,387	$367,171	$363,997	$437,261	$434,108
Operating Income [(1)]	34,395	34,403	68,059	68,065	106,409	106,409

	2011 Three Months Ended							
	March 31,		June 30,		September 30,		December 31,	
	As Reported	As Revised	As Reported	As Revised	As Reported	As Revised	As Reported	As Revised
	-Thousands of Dollars-							
Income Statement								
Operating Revenue	$344,766	$338,177	$369,673	$365,141	$450,947	$441,557	$344,129	$333,827
Operating Income [(1)]	44,820	44,820	71,290	71,290	123,760	123,760	41,802	41,837

(1) Includes immaterial reclassifications from Operating Expense to Other Expense to conform with current year presentation.

Schedule II—Valuation and Qualifying Accounts – UNS Energy

Description	Beginning Balance	Additions-Charged to Income	Deductions	Ending Balance
	-Millions of Dollars-			
Year Ended December 31,				
Reserve for Uncollectible Accounts [1]				
2012	$ 16	$ 4	$ 13	$ 7
2011	$ 13	$ 5	$ 2	$16
2010	$ 13	$ 4	$ 4	$13
Deferred Tax Assets Valuation Allowance [2]				
2012	$ 7	$—	$—	$ 7
2011	$ 8	$—	$ 1	$ 7
2010	$—	$ 8	$—	$ 8
Other [3]				
2012	$ 6			$ 9
2011	$ 4			$ 6
2010	$ 2			$ 4

(1) TEP, UNS Gas, and UNS Electric record additions to the Reserve for Uncollectible Accounts based on historical experience and any specific customer collection issues identified. Deductions principally reflect amounts charged off as uncollectible, less amounts recovered. Amounts include reserves for trade receivables, wholesale sales, and in-kind transmission imbalances.

(2) Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or the entire deferred income tax asset will not be realized. Management believes that it is more likely than not that we will not be able to generate future capital gains to offset the capital losses related to an unregulated investment loss deferred tax asset. As a result, an $8 million valuation allowance was recorded against the deferred tax asset as of December 31, 2010.

(3) Principally reserves for sales tax audits, litigation matters, and damages billable to third parties. As the Other reserves are not individually significant, additions and deductions need not be disclosed.

Schedule II—Valuation and Qualifying Accounts—TEP

Description	Beginning Balance	Additions-Charged to Income	Deductions	Ending Balance
	-Millions of Dollars-			
Year Ended December 31,				
Reserve for Uncollectible Accounts [1]				
2012	$ 14	$3	$12	$ 5
2011	$ 11	$4	$ 1	$14
2010	$ 11	$3	$ 3	$11
Other [2]				
2012	$ 4			$ 8
2011	$ 3			$ 4
2010	$—			$ 3

(1) TEP records additions to the Reserve for Uncollectible Accounts based on historical experience and any specific customer collection issues identified. Deductions principally reflect amounts charged off as uncollectible, less amounts recovered. Amounts include reserves for trade receivables, wholesales sales, and in-kind transmission imbalances.

(2) Principally reserves for sales tax audits, litigation matters, and damages billable to third parties. As the Other reserves are not individually significant, additions and deductions need not be disclosed.

TEP had no deferred tax assets valuation allowance in the periods presented.

UNS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Three Months Ended September 30, 2013 (Unaudited)	Three Months Ended September 30, 2012 (Unaudited)		Nine Months Ended September 30, 2013 (Unaudited)	Nine Months Ended September 30, 2012 (Unaudited)
Thousands of Dollars (Except Per Share Amounts)			Thousands of Dollars (Except Per Share Amounts)	
		Operating Revenues		
$362,244	$353,473	Electric Retail Sales	**$ 868,523**	$ 850,975
27,529	29,341	Electric Wholesale Sales	**92,581**	88,469
15,430	15,407	Gas Retail Sales	**86,432**	85,621
31,838	35,887	Other Revenues	**86,863**	88,427
437,041	434,108	**Total Operating Revenues**	**1,134,399**	1,113,492
		Operating Expenses		
85,102	92,873	Fuel	**253,249**	245,933
67,429	57,085	Purchased Energy	**189,384**	165,078
8,061	4,500	Transmission and Other PPFAC Recoverable Costs	**15,768**	10,738
(3,521)	18,076	Increase (Decrease) to Reflect PPFAC/PGA Recovery Treatment	**(6,814)**	29,730
157,071	172,534	**Total Fuel and Purchased Energy**	**451,587**	451,479
93,202	98,346	Operations and Maintenance	**278,245**	283,587
38,204	35,145	Depreciation	**111,175**	105,319
5,193	9,069	Amortization	**21,600**	26,845
13,606	12,605	Taxes Other Than Income Taxes	**41,329**	37,385
307,276	327,699	**Total Operating Expenses**	**903,936**	904,615
129,765	106,409	**Operating Income**	**230,463**	208,877
		Other Income (Deductions)		
2	340	Interest Income	**31**	981
2,044	1,011	Other Income	**5,545**	3,855
(438)	(752)	Other Expense	**(1,817)**	(1,508)
731	581	Appreciation (Depreciation) in Fair Value of Investments	**1,864**	1,621
2,339	1,180	**Total Other Income (Deductions)**	**5,623**	4,949
		Interest Expense		
17,580	17,074	Long-Term Debt	**53,534**	53,811
6,323	8,507	Capital Leases	**18,821**	25,105
230	692	Other Interest Expense	**183**	1,712
(933)	(459)	Interest Capitalized	**(2,352)**	(1,646)
23,200	25,814	**Total Interest Expense**	**70,186**	78,982
108,904	81,775	**Income Before Income Taxes**	**165,900**	134,844
40,914	31,111	Income Tax Expense	**51,947**	51,430
$ 67,990	$ 50,664	**Net Income**	**$ 113,953**	$ 83,414
		Weighted-Average Shares of Common Stock Outstanding (000)		
41,650	41,446	Basic	**41,596**	39,983
42,028	41,863	Diluted	**41,941**	41,719
		Earnings Per Share		
$ 1.63	$ 1.22	Basic	**$ 2.74**	$ 2.09
$ 1.62	$ 1.21	Diluted	**$ 2.72**	$ 2.03
$ 0.435	$ 0.43	**Dividends Declared Per Share**	**$ 1.305**	$ 1.29

See Notes to Condensed Consolidated Financial Statements.

UNS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Three Months Ended September 30, 2013 (Unaudited)	Three Months Ended September 30, 2012 (Unaudited)		Nine Months Ended September 30, 2013 (Unaudited)	Nine Months Ended September 30, 2012 (Unaudited)
Thousands of Dollars			Thousands of Dollars	
		Comprehensive Income		
$67,990	$50,664	Net Income	**$113,953**	$83,414
		Other Comprehensive Income		
		Net Changes in Fair Value of Cash Flow Hedges:		
685	370	net of income tax expense of $(448) and $(244)		
		net of income tax expense of $(1,459) and $(421)	**2,229**	641
		Supplemental Executive Retirement Plan (SERP) Benefit Amortization:		
68	55	net of income tax expense of $(42) and $(34)		
		net of income tax expense of $(127) and $(50)	**205**	219
753	425	**Total Other Comprehensive Income, Net of Income Tax Expense**	**2,434**	860
$68,743	$51,089	**Total Comprehensive Income**	**$116,387**	$84,274

See Notes to Condensed Consolidated Financial Statements.

UNS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2013	2012
	(Unaudited)	
	Thousands of Dollars	
Cash Flows from Operating Activities		
Cash Receipts from Electric Retail Sales	**$ 912,098**	$ 894,195
Cash Receipts from Electric Wholesale Sales	**118,341**	107,854
Cash Receipts from Gas Retail Sales	**109,994**	114,055
Cash Receipts from Operating Springerville Units 3 & 4	**75,552**	75,715
Cash Receipts from Gas Wholesale Sales	**3,558**	565
Interest Received	**516**	2,884
Income Tax Refunds Received	**—**	307
Other Cash Receipts	**23,514**	18,810
Fuel Costs Paid	**(218,712)**	(239,397)
Purchased Energy Costs Paid	**(217,522)**	(189,927)
Payment of Operations and Maintenance Costs	**(199,939)**	(207,780)
Taxes Other Than Income Taxes Paid, Net of Amounts Capitalized	**(124,782)**	(128,513)
Wages Paid, Net of Amounts Capitalized	**(96,899)**	(94,815)
Interest Paid, Net of Amounts Capitalized	**(50,108)**	(52,593)
Capital Lease Interest Paid	**(21,698)**	(27,895)
Income Taxes Paid	**(316)**	—
Other Cash Payments	**(8,563)**	(5,327)
Net Cash Flows—Operating Activities	**305,034**	268,138
Cash Flows from Investing Activities		
Capital Expenditures	**(238,463)**	(232,036)
Purchase of Intangibles—Renewable Energy Credits	**(20,429)**	(7,554)
Deposit—San Juan Mine Reclamation Trust	**—**	(1,107)
Other Cash Payments	**—**	(232)
Return of Investments in Springerville Lease Debt	**9,104**	19,278
Restricted Cash Released	**4,500**	—
Proceeds from Note Receivable	**—**	12,500
Insurance Proceeds for Replacement Assets	**—**	2,875
Other Cash Receipts	**6,625**	14,484
Net Cash Flows—Investing Activities	**(238,663)**	(191,792)
Cash Flows from Financing Activities		
Proceeds from Borrowings Under Revolving Credit Facilities	**130,000**	342,000
Repayments of Borrowings Under Revolving Credit Facilities	**(100,000)**	(346,000)
Payments of Capital Lease Obligations	**(99,621)**	(89,452)
Common Stock Dividends Paid	**(54,146)**	(51,852)
Proceeds from Issuance of Long-Term Debt	**—**	149,513
Repayments of Long-Term Debt	**—**	(9,341)
Payment of Debt Issue/Retirement Costs	**(1,022)**	(3,349)
Proceeds from Stock Options Exercised	**2,724**	3,529
Proceeds from Common Stock Issuance	**408**	—
Other Cash Receipts	**4,721**	2,935
Other Cash Payments	**(962)**	(718)
Net Cash Flows—Financing Activities	**(117,898)**	(2,735)
Net Increase (Decrease) in Cash and Cash Equivalents	**(51,527)**	73,611
Cash and Cash Equivalents, Beginning of Year	**123,918**	76,390
Cash and Cash Equivalents, End of Period	**$ 72,391**	$ 150,001

See Note 10 for supplemental cash flow information.

See Notes to Condensed Consolidated Financial Statements.

UNS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2013 (Unaudited)	December 31, 2012
	Thousands of Dollars	
ASSETS		
Utility Plant		
Plant in Service	**$ 5,114,426**	$ 5,005,768
Utility Plant Under Capital Leases	**621,247**	582,669
Construction Work in Progress	**211,100**	128,621
Total Utility Plant	**5,946,773**	5,717,058
Less Accumulated Depreciation and Amortization	**(1,966,801)**	(1,921,733)
Less Accumulated Amortization of Capital Lease Assets	**(509,712)**	(494,962)
Total Utility Plant—Net	**3,470,260**	3,300,363
Investments and Other Property		
Investments in Lease Equity	**36,230**	36,339
Other	**33,441**	36,537
Total Investments and Other Property	**69,671**	72,876
Current Assets		
Cash and Cash Equivalents	**72,391**	123,918
Accounts Receivable—Customer	**127,316**	93,742
Unbilled Accounts Receivable	**55,730**	53,568
Allowance for Doubtful Accounts	**(7,215)**	(6,545)
Materials and Supplies	**89,302**	93,322
Fuel Inventory	**44,458**	62,019
Deferred Income Taxes—Current	**66,520**	34,260
Regulatory Assets—Current	**52,709**	51,619
Investments in Lease Debt	**—**	9,118
Derivative Instruments	**1,620**	3,165
Other	**26,882**	33,567
Total Current Assets	**529,713**	551,753
Regulatory and Other Assets		
Regulatory Assets—Noncurrent	**200,705**	191,077
Derivative Instruments	**752**	3,801
Other Assets	**22,704**	20,559
Total Regulatory and Other Assets	**224,161**	215,437
Total Assets	**$ 4,293,805**	$ 4,140,429

See Notes to Condensed Consolidated Financial Statements.

UNS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS—(continued)

	September 30, 2013 (Unaudited)	December 31, 2012
	Thousands of Dollars	
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity	**$1,132,286**	$1,065,465
Capital Lease Obligations	**130,088**	262,138
Long-Term Debt	**1,505,536**	1,498,442
Total Capitalization	**2,767,910**	2,826,045
Current Liabilities		
Current Obligations Under Capital Leases	**169,060**	90,583
Borrowings Under Revolving Credit Facilities	**23,000**	—
Accounts Payable—Trade	**91,615**	107,740
Accrued Taxes Other than Income Taxes	**60,657**	41,939
Accrued Employee Expenses	**26,000**	24,094
Accrued Interest	**22,343**	31,950
Regulatory Liabilities—Current	**56,987**	43,516
Customer Deposits	**30,564**	34,048
Derivative Instruments	**12,988**	14,742
Other	**14,521**	10,517
Total Current Liabilities	**507,735**	399,129
Deferred Credits and Other Liabilities		
Deferred Income Taxes—Noncurrent	**482,516**	364,756
Regulatory Liabilities—Noncurrent	**297,699**	279,111
Pension and Other Retiree Benefits	**141,997**	159,401
Derivative Instruments	**7,183**	12,709
Other	**88,765**	99,278
Total Deferred Credits and Other Liabilities	**1,018,160**	915,255
Commitments, Contingencies, and Environmental Matters (Note 4)		
Total Capitalization and Other Liabilities	**$4,293,805**	$4,140,429

See Notes to Condensed Consolidated Financial Statements.

UNS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY

	Common Shares Outstanding*	Common Stock	Accumulated Earnings	Accumulated Other Comprehensive Loss	Total Stockholders' Equity
	Thousands of Shares		(Unaudited) Thousands of Dollars		
Balances at December 31, 2012	**41,344**	**$882,138**	**$193,117**	**$(9,790)**	**$1,065,465**
Comprehensive Income					
2013 Year-to-Date Net Income			113,953		113,953
Other Comprehensive Income, net of $(1,586) income taxes				2,434	2,434
Total Comprehensive Income					116,387
Dividends, Including Non-Cash Dividend Equivalents			(54,733)		(54,733)
Shares Issued Under Dividend Reinvestment Plan	9	408			408
Shares Issued for Stock Options	85	2,724			2,724
Shares Issued Under Performance Share Awards	57	—			—
Other		2,035			2,035
Balances at September 30, 2013	**41,495**	**$887,305**	**$252,337**	**$(7,356)**	**$1,132,286**

* UNS Energy has 75 million authorized shares of Common Stock.

See Notes to Condensed Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Three Months Ended September 30, 2013 (Unaudited) Thousands of Dollars	2012		Nine Months Ended September 30, 2013 (Unaudited) Thousands of Dollars	2012
		Operating Revenues		
$310,632	$302,893	Electric Retail Sales	**$739,147**	$716,993
26,563	25,448	Electric Wholesale Sales	**90,503**	77,488
34,044	38,569	Other Revenues	**93,603**	95,826
371,239	366,910	**Total Operating Revenues**	**923,253**	890,307
		Operating Expenses		
82,065	88,402	Fuel	**247,417**	237,930
42,477	27,576	Purchased Power	**89,815**	62,064
4,940	1,914	Transmission and Other PPFAC Recoverable Costs	**7,535**	4,277
(7,992)	20,025	Increase (Decrease) to Reflect PPFAC Recovery Treatment	**(5,079)**	25,150
121,490	137,917	**Total Fuel and Purchased Energy**	**339,688**	329,421
79,335	86,942	Operations and Maintenance	**239,170**	248,092
30,311	27,644	Depreciation	**87,729**	82,656
6,118	10,001	Amortization	**24,393**	29,621
10,808	10,327	Taxes Other Than Income Taxes	**32,916**	30,325
248,062	272,831	**Total Operating Expenses**	**723,896**	720,115
123,177	94,079	**Operating Income**	**199,357**	170,192
		Other Income (Deductions)		
6	28	Interest Income	**14**	97
1,466	952	Other Income	**3,904**	3,041
(2,776)	(1,945)	Other Expense	**(7,493)**	(4,886)
731	581	Appreciation (Depreciation) in Fair Value of Investments	**1,864**	1,621
(573)	(384)	**Total Other Income (Deductions)**	**(1,711)**	(127)
		Interest Expense		
13,848	13,268	Long-Term Debt	**42,412**	40,562
6,323	8,507	Capital Leases	**18,821**	25,105
82	562	Other Interest Expense	**(86)**	1,338
(644)	(361)	Interest Capitalized	**(1,671)**	(1,381)
19,609	21,976	**Total Interest Expense**	**59,476**	65,624
102,995	71,719	**Income Before Income Taxes**	**138,170**	104,441
38,828	27,150	Income Tax Expense	**41,737**	39,423
$64,167	$ 44,569	**Net Income**	**$ 96,433**	$ 65,018

See Notes to Condensed Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Three Months Ended September 30, 2013 (Unaudited)	Three Months Ended September 30, 2012 (Unaudited)		Nine Months Ended September 30, 2013 (Unaudited)	Nine Months Ended September 30, 2012 (Unaudited)
Thousands of Dollars			Thousands of Dollars	
		Comprehensive Income		
$64,167	$44,569	Net Income	**$96,433**	$65,018
		Other Comprehensive Income		
		Net Changes in Fair Value of Cash Flow Hedges:		
700	465	net of income tax expense of $(458) and $(304)		
		net of income tax expense of $(1,412) and $(584)	**2,156**	891
		SERP Benefit Amortization:		
68	55	net of income tax expense of $(42) and $(34)		
		net of income tax expense of $(127) and $(50)	**205**	219
768	520	**Total Other Comprehensive Income, Net of Income Tax Expense**	**2,361**	1,110
$64,935	$45,089	**Total Comprehensive Income**	**$98,794**	$66,128

See Notes to Condensed Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2013	2012
	(Unaudited)	
	Thousands of Dollars	
Cash Flows from Operating Activities		
Cash Receipts from Electric Retail Sales	**$ 769,433**	$ 748,936
Cash Receipts from Electric Wholesale Sales	**107,997**	89,902
Cash Receipts from Operating Springerville Units 3 & 4	**75,552**	75,715
Reimbursement of Affiliate Charges	**17,639**	16,783
Cash Receipts from Gas Wholesale Sales	**3,209**	153
Interest Received	**509**	2,014
Income Tax Refunds Received	**77**	200
Other Cash Receipts	**18,240**	14,528
Fuel Costs Paid	**(214,722)**	(233,457)
Payment of Operations and Maintenance Costs	**(193,290)**	(200,569)
Taxes Other Than Income Taxes Paid, Net of Amounts Capitalized	**(97,419)**	(99,249)
Purchased Power Costs Paid	**(87,110)**	(60,684)
Wages Paid, Net of Amounts Capitalized	**(80,964)**	(77,820)
Interest Paid, Net of Amounts Capitalized	**(36,671)**	(35,728)
Capital Lease Interest Paid	**(21,698)**	(27,893)
Income Taxes Paid	**—**	(1,796)
Other Cash Payments	**(6,603)**	(3,884)
Net Cash Flows—Operating Activities	**254,179**	207,151
Cash Flows from Investing Activities		
Capital Expenditures	**(180,451)**	(196,429)
Purchase of Intangibles—Renewable Energy Credits	**(17,552)**	(6,436)
Deposit—San Juan Mine Reclamation Trust	**—**	(1,107)
Return of Investments in Springerville Lease Debt	**9,104**	19,278
Restricted Cash Released	**4,500**	—
Insurance Proceeds for Replacement Assets	**—**	2,875
Other Cash Receipts	**4,656**	9,207
Net Cash Flows—Investing Activities	**(179,743)**	(172,612)
Cash Flows from Financing Activities		
Proceeds from Borrowings Under Revolving Credit Facility	**78,000**	189,000
Repayments of Borrowings Under Revolving Credit Facility	**(78,000)**	(199,000)
Payments of Capital Lease Obligations	**(99,621)**	(89,452)
Dividends Paid to UNS Energy	**(20,000)**	—
Proceeds from Issuance of Long-Term Debt	**—**	149,513
Repayments of Long-Term Debt	**—**	(6,535)
Payment of Debt Issue/Retirement Costs	**(1,022)**	(3,349)
Other Cash Receipts	**1,976**	1,292
Other Cash Payments	**(726)**	(530)
Net Cash Flows—Financing Activities	**(119,393)**	40,939
Net Increase (Decrease) in Cash and Cash Equivalents	**(44,957)**	75,478
Cash and Cash Equivalents, Beginning of Year	**79,743**	27,718
Cash and Cash Equivalents, End of Period	**$ 34,786**	$ 103,196

See Note 10 for supplemental cash flow information.

See Notes to Condensed Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY

CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2013 (Unaudited)	December 31, 2012
	Thousands of Dollars	
ASSETS		
Utility Plant		
Plant in Service	**$ 4,434,770**	$ 4,348,041
Utility Plant Under Capital Leases	**621,247**	582,669
Construction Work in Progress	**153,258**	98,460
Total Utility Plant	**5,209,275**	5,029,170
Less Accumulated Depreciation and Amortization	**(1,811,806)**	(1,783,787)
Less Accumulated Amortization of Capital Lease Assets	**(509,712)**	(494,962)
Total Utility Plant—Net	**2,887,757**	2,750,421
Investments and Other Property		
Investments in Lease Equity	**36,230**	36,339
Other	**32,009**	35,091
Total Investments and Other Property	**68,239**	71,430
Current Assets		
Cash and Cash Equivalents	**34,786**	79,743
Accounts Receivable—Customer	**105,646**	71,813
Unbilled Accounts Receivable	**46,240**	33,782
Allowance for Doubtful Accounts	**(5,238)**	(4,598)
Accounts Receivable—Due from Affiliates	**3,963**	5,720
Materials and Supplies	**76,255**	80,377
Fuel Inventory	**44,162**	61,737
Deferred Income Taxes—Current	**69,985**	37,212
Regulatory Assets—Current	**36,283**	34,345
Investments in Lease Debt	**—**	9,118
Derivative Instruments	**1,047**	2,230
Other	**20,605**	32,163
Total Current Assets	**433,734**	443,642
Regulatory and Other Assets		
Regulatory Assets—Noncurrent	**186,626**	178,330
Derivative Instruments	**259**	1,354
Other Assets	**17,525**	15,869
Total Regulatory and Other Assets	**204,410**	195,553
Total Assets	**$ 3,594,140**	$ 3,461,046

See Notes to Condensed Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY

CONDENSED CONSOLIDATED BALANCE SHEETS—(Continued)

	September 30, 2013 (Unaudited)	December 31, 2012
	Thousands of Dollars	
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity	**$ 939,721**	$ 860,927
Capital Lease Obligations	**130,088**	262,138
Long-Term Debt	**1,223,536**	1,223,442
Total Capitalization	**2,293,345**	2,346,507
Current Liabilities		
Current Obligations Under Capital Leases	**169,060**	90,583
Accounts Payable—Trade	**75,834**	82,122
Accounts Payable—Due to Affiliates	**2,981**	3,134
Accrued Taxes Other than Income Taxes	**50,465**	33,060
Accrued Employee Expenses	**22,937**	20,715
Accrued Interest	**20,503**	26,965
Regulatory Liabilities—Current	**26,440**	20,822
Customer Deposits	**21,251**	24,846
Derivative Instruments	**7,060**	4,899
Other	**9,336**	7,085
Total Current Liabilities	**405,867**	314,231
Deferred Credits and Other Liabilities		
Deferred Income Taxes—Noncurrent	**421,621**	319,216
Regulatory Liabilities—Noncurrent	**259,523**	241,189
Pension and Other Retiree Benefits	**132,491**	149,718
Derivative Instruments	**4,950**	10,565
Other	**76,343**	79,620
Total Deferred Credits and Other Liabilities	**894,928**	800,308
Commitments, Contingencies, and Environmental Matters (Note 4)		
Total Capitalization and Other Liabilities	**$3,594,140**	**$3,461,046**

See Notes to Condensed Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDER'S EQUITY

	Common Stock	Capital Stock Expense	Accumulated Earnings (Deficit)	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
			(Unaudited) Thousands of Dollars		
Balances at December 31, 2012	**$888,971**	**$(6,357)**	**$(12,157)**	**$(9,530)**	**$860,927**
Comprehensive Income					
2013 Year-to-Date Net Income			96,433		96,433
Other Comprehensive Income, net of $(1,539) income taxes				2,361	2,361
Total Comprehensive Income					98,794
Dividends Paid			(20,000)		(20,000)
Balances at September 30, 2013	**$888,971**	**$(6,357)**	**$ 64,276**	**$(7,169)**	**$939,721**

See Notes to Condensed Consolidated Financial Statements.

NOTE 1. FINANCIAL STATEMENT PRESENTATION

UNS Energy Corporation (UNS Energy) is a holding company that conducts its business through three regulated public utilities: Tucson Electric Power Company (TEP); UNS Gas, Inc. (UNS Gas); and UNS Electric, Inc. (UNS Electric). References to "we" and "our" are to UNS Energy and its subsidiaries, collectively.

We prepared our condensed consolidated financial statements according to generally accepted accounting principles in the United States of America (GAAP) and the Securities and Exchange Commission's (SEC) interim reporting requirements. These condensed consolidated financial statements exclude some information and footnotes required by GAAP and the SEC for annual financial statement reporting. These condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and footnotes in our 2012 Annual Report on Form 10-K.

The condensed consolidated financial statements are unaudited, but, in management's opinion, include all recurring adjustments necessary for a fair presentation of the results for the interim periods presented. Because weather and other factors cause seasonal fluctuations in sales, our quarterly results are not indicative of annual operating results. UNS Energy and TEP reclassified certain amounts in the financial statements to conform to current year presentation.

REVISION OF PRIOR PERIOD UNS ENERGY INCOME STATEMENT

During the first three quarters of 2012, we incorrectly reported UNS Electric's sales and purchase contracts which did not result in the physical delivery of energy. The transactions were reported on a gross basis rather than on a net basis. This error resulted in an equal and offsetting overstatement of Electric Wholesale Sales and Purchased Energy in the income statements of $3 million for the three months ended and $10 million for the nine months ended September 30, 2012. This error had no impact on operating income, net income, accumulated earnings, or cash flows.

We assessed the impact of this error on prior period financial statements and concluded it was not material to any period. However, this error was significant to individual income statement line items. As a result, in accordance with GAAP, we revised our prior period income statement as follows:

	UNS Energy			
	Three Months Ended September 30, 2012		Nine Months Ended September 30, 2012	
	As Reported	As Revised	As Reported	As Revised
	Thousands of Dollars		Thousands of Dollars	
Income Statement				
Electric Wholesale Sales	$ 32,494	$ 29,341	$ 98,282	$ 88,469
Purchased Energy	60,238	57,085	174,891	165,078
Total Fuel and Purchased Energy	175,687	172,534	461,292	451,479
Total Operating Expenses	330,852	327,699	914,428	904,615

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

In 2013, we adopted authoritative guidance that:

- Requires disclosure related to offsetting derivative assets and derivative liabilities in accordance with GAAP. See Note 11.
- Requires additional disclosures for amounts reclassified out of Accumulated Other Comprehensive Income (AOCI) by component. See Note 12.
- Allows an entity to perform a qualitative analysis to determine if additional testing for impairment of indefinite-lived intangible assets is required. Based on our qualitative analysis, we had no impairment indicator as our only indefinite-lived intangible assets, Renewable Energy Credits (RECs), are currently recoverable under the Renewable Energy Standard (RES) as we use the RECs to comply with the standard's renewable resources requirements.

NOTE 2. REGULATORY MATTERS

RATES AND REGULATION

The Arizona Corporation Commission (ACC) and the Federal Energy Regulatory Commission (FERC) each regulate portions of the utility accounting practices and rates of TEP, UNS Gas, and UNS Electric. The ACC regulates rates charged to retail customers, the siting of generation and transmission facilities, the issuance of securities, and transactions with affiliated parties. The FERC regulates terms and prices of transmission services and wholesale electricity sales.

2013 TEP RATE ORDER

In June 2013, the ACC issued the 2013 TEP Rate Order that resolved the rate case filed by TEP in July 2012 which was based on a test year ended December 31, 2011. The 2013 TEP Rate Order approved new rates effective July 1, 2013.

The provisions of the 2013 TEP Rate Order include, but are not limited to:

- an increase in non-fuel retail Base Rates of approximately $76 million over adjusted test year revenues;
- an Original Cost Rate Base (OCRB) of approximately $1.5 billion and a Fair Value Rate Base (FVRB) of approximately $2.3 billion;
- a return on equity of 10.0%, a long-term cost of debt of 5.18%, and a short-term cost of debt of 1.42%, resulting in a weighted average cost of capital of 7.26%;
- a capital structure of approximately 43.5% equity, 56.0% long-term debt, and 0.5% short-term debt;
- a 0.68% return on the fair value increment of rate base (the fair value increment of rate base represents the difference between OCRB and FVRB of approximately $800 million);
- a revision in depreciation rates from an average rate of 3.32% to 3.0% for generation and distribution plant, primarily due to revised estimates of asset removal costs, which will have the effect of reducing depreciation expense by approximately $11 million annually; and
- an agreement by TEP to seek recovery of costs related to the Nogales transmission line from the FERC before seeking rate recovery from the ACC.

The 2013 TEP Rate Order also includes the following cost recovery mechanisms:

- a new Purchased Power and Fuel Adjustment Clause (PPFAC) credit of $0.001388 per kWh effective July 1, 2013. The credit reflects the following:
    - a one-time reduction in the PPFAC bank balance, recorded in June 2013 as an increase to fuel expense, of $3 million related to prior Sulfur Credits; and
    - a transfer of $10 million, recorded in June 2013, from the PPFAC bank balance to a new regulatory asset to defer coal costs related to the San Juan mine fire. These costs will be eligible for recovery through the PPFAC upon final insurance settlement.
- a modification of the PPFAC mechanism to include recovery of generation-related lime costs offset by Sulfur Credits.
- a Lost Fixed Cost Recovery mechanism (LFCR) to recover certain non-fuel costs related to kWh sales lost due to energy efficiency programs and distributed generation, subject to ACC approval and a year-over-year cap of 1% of TEP's total retail revenues. TEP expects the LFCR rate, recovering 2013 costs, to be effective on July 1, 2014, upon approval of verified lost kWh sales by the ACC.
- an Environmental Compliance Adjustor (ECA) mechanism to recover certain capital carrying costs to comply with government-mandated environmental regulations between rate cases. The ECA rate is capped at $0.00025 per kWh, which approximates 0.25% of TEP's total retail revenues, and will be charged to customers beginning in May 2014 for any qualifying costs incurred between August 2013 and December 2013.
- an energy efficiency provision which includes a 2013 calendar year budget to fund programs that support the ACC's Electric Energy Efficiency Standards, as well as a performance incentive.

PENDING UNS ELECTRIC RATE CASE

In December 2012, UNS Electric filed a rate case application with the ACC as required by the ACC in UNS Electric's 2010 Rate Order. UNS Electric's rate filing was based on a test year ended June 30, 2012.

In September 2013, UNS Electric, the staff of the ACC, and certain other parties to UNS Electric's pending rate case proceeding entered into a settlement agreement (2013 UNS Electric Settlement Agreement). The 2013 UNS Electric Settlement Agreement requires the approval of the ACC before new rates can become effective.

The terms of the 2013 UNS Electric Settlement Agreement include, but are not limited to:

- an increase in non-fuel retail Base Rates of approximately $3 million;
- an OCRB of approximately $213 million and a FVRB of approximately $283 million;
- a return on equity of 9.50% and a long-term cost of debt of 5.97% resulting in a weighted average cost of capital of 7.83%;
- a 0.50% return on the fair value increment of rate base (the fair value increment of rate base represents the difference between OCRB and FVRB of approximately $70 million); and
- a capital structure of 52.6% equity and 47.4% long-term debt.

The 2013 UNS Electric Settlement Agreement also includes the following cost recovery mechanisms:

- an LFCR mechanism to recover certain non-fuel costs related to kWh sales lost due to energy efficiency programs and distributed generation; and
- a Transmission Cost Adjustor (TCA). The TCA would allow more timely recovery of transmission costs associated with serving retail customers.

UNS GAS PURCHASED GAS ADJUSTOR

In October 2013, the ACC approved an increase to the existing Purchased Gas Adjustor (PGA) credit from 4.5 cents per therm to 10 cents per therm in order to reduce the over-collected PGA bank balance. The new PGA credit will be effective for the period November 1, 2013 through April 30, 2014. At September 30, 2013, the PGA bank balance was over-collected by $17 million on a billed-to-customer basis.

REGULATORY ASSETS AND LIABILITIES

The following table summarizes changes in regulatory assets and liabilities since December 31, 2012:

	September 30, 2013		December 31, 2012	
	UNS Energy	TEP	UNS Energy	TEP
	Millions of Dollars			
Regulatory Assets – Current	$ 53	$ 36	$ 52	$ 34
Regulatory Assets – Noncurrent [1]	201	187	191	178
Regulatory Liabilities – Current [2]	(57)	(26)	(44)	(21)
Regulatory Liabilities – Noncurrent [3]	(298)	(260)	(279)	(241)
Total Net Regulatory Assets (Liabilities)	$(101)	$ (63)	$ (80)	$ (50)

(1) Regulatory Assets – Noncurrent increased reflecting a newly created regulatory asset primarily for the investment tax credit basis adjustment. See Note 6. This regulatory asset does not earn a return and will be recovered through future rates. The increase is also related to the addition of deferred rate case costs that do not earn a return and will be recovered over a four year period.

(2) Regulatory Liabilities – Current increased because purchased energy costs are over recovered following deferral of coal costs related to the San Juan mine fire, as discussed above. The regulatory asset related to these deferred costs does not earn a return and will be recovered at the time of the final insurance settlement.

(3) Regulatory Liabilities – Noncurrent increased due to the collection of amounts in rates for future asset removal costs that have not yet been expended.

FUTURE IMPLICATIONS OF DISCONTINUING APPLICATION OF REGULATORY ACCOUNTING

If our regulated operations no longer met the requirements to apply regulatory accounting we would remove our regulatory assets and liabilities by:

- writing off the remaining regulatory assets as an expense and regulatory liabilities as income in the income statements; and
- reflecting regulatory pension assets as part of AOCI.

If we had stopped applying regulatory accounting at September 30, 2013:

- TEP would have recorded an extraordinary after-tax gain of $113 million and an after-tax loss in AOCI of $75 million;
- UNS Gas would have recorded an extraordinary after-tax gain of $26 million and an after-tax loss in AOCI of $2 million; and
- UNS Electric would have recorded an extraordinary after-tax gain of $3 million and an after-tax loss in AOCI of $3 million.

While future regulatory orders and market conditions may affect cash flows, our cash flows would not be affected if we stopped applying regulatory accounting to our regulated operations.

NOTE 3. BUSINESS SEGMENTS

We have three reportable segments regularly reviewed by our chief operating decision makers to evaluate performance and make operating decisions.

(1) TEP, a regulated electric utility and our largest subsidiary

(2) UNS Gas, a regulated gas distribution utility

(3) UNS Electric, a regulated electric utility

We disclose selected financial data for our reportable segments in the following table:

	Reportable Segments					
	TEP	UNS Gas	UNS Electric	Non-Reportable Segments	Reconciling Adjustments	UNS Energy Consolidated
	Millions of Dollars					
Income Statement						
Three Months Ended September 30, 2013						
Operating Revenues – External	$367	$ 16	$ 54	$—	$—	$437
Operating Revenues – Intersegment [1]	4	2	—	4	(10)	—
Net Income	64	(1)	5	—	—	68
Three Months Ended September 30, 2012						
Operating Revenues – External	$362	$ 16	$ 56	$—	$—	$434
Operating Revenues – Intersegment [1]	5	2	—	5	(12)	—
Net Income	45	—	6	—	—	51

	Reportable Segments					
	TEP	UNS Gas	UNS Electric	Non-Reportable Segments	Reconciling Adjustments	UNS Energy Consolidated
	Millions of Dollars					
Income Statement						
Nine Months Ended September 30, 2013						
Operating Revenues – External	$910	$90	$134	$—	$—	$1,134
Operating Revenues – Intersegment [1]	13	3	1	12	(29)	—
Net Income	96	6	11	1	—	114
Nine Months Ended September 30, 2012						
Operating Revenues – External	$877	$89	$147	$—	$—	$1,113
Operating Revenues – Intersegment [1]	13	4	1	14	(32)	—
Net Income	65	5	14	(1)	—	83

[1] Operating Revenues – Intersegment: TEP includes control area services provided to UNS Electric based on a FERC-approved tariff; common costs (systems, facilities, etc.) allocated to affiliates on a cost-causative basis; and sales of power to UNS Electric at third-party market prices. Other primarily includes meter reading services and supplemental workforce provided by an unregulated affiliate to the utilities.

NOTE 4. COMMITMENTS, CONTINGENCIES, AND ENVIRONMENTAL MATTERS

In addition those reported in our 2012 Annual Report on Form 10-K, we entered into the following new long-term commitments through September 30, 2013:

TEP COMMITMENTS

	Purchase Commitments						
	2013	2014	2015	2016	2017	Thereafter	Total
	Millions of Dollars						
Purchased Power, Including Renewable PPA [1]	$ 2	$ 18	$ 6	$ 4	$ 4	$ 58	$ 92
Capital Lease Obligations [2]	—	—	46	—	—	—	46
RES Performance-Based Incentives [3]	1	1	1	1	1	7	12
Fuel Transportation [4]	4	5	5	5	5	1	25
Total Purchase Commitments	$ 7	$ 24	$58	$ 10	$ 10	$ 66	$175

(1) Purchased Power costs are recoverable from customers through the PPFAC. A portion of the Renewable Power Purchase Agreement (PPA) is recoverable through the PPFAC, with the balance recoverable through the RES tariff.
(2) In the third and fourth quarters of 2013, TEP entered into agreements to purchase certain Springerville Unit 1 leased interests. See Note 5.
(3) The RES Performance-Based Incentive (PBI) costs are recoverable through the RES tariff.
(4) Fuel Transportation costs are recoverable from customers through the PPFAC.

UNS GAS COMMITMENTS

Forward Energy Contracts

UNS Gas entered into new forward energy commitments that settle through 2016 at fixed prices per million British thermal units (MMBtu). UNS Gas' minimum payment obligations for these purchases are $2 million in 2014, $3 million in 2015, and $2 million in 2016.

Fuel Transportation

UNS Gas entered into revised gas transportation agreements in August 2013. UNS Gas anticipates that its commitments will increase by $3 million in 2013, $9 million each year in 2014 through 2016, $10 million in 2017, and $56 million thereafter.

UNS ELECTRIC COMMITMENTS

Purchased Power Contracts

UNS Electric entered into new forward purchased power commitments that will settle through 2015 at fixed prices per MWh. UNS Electric's minimum payment obligations for these purchases are $1 million in 2014 and $4 million in 2015.

TEP CONTINGENCIES

Claim Related to San Juan Generating Station

San Juan Coal Company (SJCC) operates an underground coal mine in an area where certain gas producers have oil and gas leases with the federal government, the State of New Mexico, and private parties. These gas producers allege that SJCC's underground coal mine interferes with their operations, reducing the amount of natural gas they can recover. SJCC compensated certain gas producers for any remaining production from wells deemed close enough to the mine to warrant plugging and abandoning them. These settlements, however, do not resolve all potential claims by gas producers in the area. TEP owns 50% of Units 1 and 2 at San Juan Generating Station (San Juan), which represents approximately 20% of the total generation capacity at San Juan, and is responsible for its share of any settlements. TEP cannot estimate the impact of any future claims by these gas producers on the cost of coal at San Juan.

In August 2013, the Bureau of Land Management (BLM) proposed regulations that, among other things, redefine the term "underground mine" to exclude high-wall mining operations and impose a higher surface mine coal royalty on high-wall mining. SJCC utilized high-wall mining techniques at its surface mines prior to beginning underground mining operations in January 2003. If the proposed regulations become effective, SJCC may be subject to additional royalties on coal delivered to San Juan between August 2000 and January 2003 totaling approximately $5 million of which TEP's proportionate share would approximate $1 million. TEP cannot predict the final outcome of the BLM's proposed regulations.

Claims Related to Four Corners Generating Station

In October 2011, EarthJustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New Mexico against Arizona Public Service Company (APS) and the other Four Corners Generating Station (Four Corners) participants alleging violations of the Prevention of Significant Deterioration (PSD) provisions of the Clean Air Act at Four Corners. In January 2012, EarthJustice amended their complaint alleging violations of New Source Performance Standards resulting from equipment replacements at Four Corners. Among other things, the plaintiffs seek to have the court issue an order to cease operations at Four Corners until any required PSD permits are issued and order the payment of civil penalties, including a beneficial mitigation project. In April 2012, APS filed motions to dismiss with the court for all claims asserted by EarthJustice in the amended complaint. All parties filed a joint motion to stay until December 1, 2013.

TEP owns 7% of Four Corners Units 4 and 5 and is liable for its share of any resulting liabilities. TEP cannot predict the final outcome of the claims relating to Four Corners, and, due to the general and non-specific nature of the claims and the indeterminate scope and nature of the injunctive relief sought for this claim, TEP cannot determine estimates of the range of loss at this time. TEP accrued estimated losses of less than $1 million in 2011 for this claim based on its share of a settlement offer to resolve the claim.

In May 2013, the New Mexico Taxation and Revenue Department issued a notice of assessment for coal severance tax, penalties, and interest totaling $30 million to the coal supplier at Four Corners. The coal supplier and Four Corners' operating agent intend to contest the validity of the assessment on behalf of the participants in Four Corners, who will be liable for their share of any resulting liabilities. TEP's share of the assessment based on its ownership of Four Corners is approximately $1 million. TEP cannot predict the outcome or timing of resolution of this claim.

Mine Closure Reclamation at Generating Stations Not Operated by TEP

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which TEP has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing Navajo, San Juan, and Four Corners. TEP's share of reclamation costs is expected to be $27 million upon expiration of the coal supply agreements, which expire between 2016 and 2019. The reclamation liability (present value of future liability) recorded was $18 million at September 30, 2013 and $16 million at December 31, 2012.

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 credit-adjusted risk-free interest rate to be used to discount future liabilities. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreements' terms. TEP does not believe that recognition of its final reclamation obligations will be material to TEP in any single year because recognition will occur over the remaining terms of its coal supply agreements.

TEP's PPFAC allows us to pass through most fuel costs, including final reclamation costs, to customers. Therefore, TEP classifies these costs as a regulatory asset by increasing the regulatory asset and the reclamation liability over the remaining life of the coal supply agreements on an accrual basis and recovering the regulatory asset through the PPFAC as final mine reclamation costs are paid to the coal suppliers.

Tucson to Nogales Transmission Line

TEP and UNS Electric are parties to a project development agreement for the joint construction of a 60-mile transmission line from Tucson, Arizona to Nogales, Arizona. This project was initiated in response to an order by the ACC to UNS Electric to improve the reliability of electric service in Nogales. TEP and UNS Electric expect to abandon the project based on the cost of the proposed 345-kV line, the difficulty in reaching agreement with the Forest Service on a path for the line, and concurrence by the ACC of recent transmission plans filed by TEP and UNS Electric supporting elimination of this project. As part of the 2013 TEP Rate Order, TEP agreed to seek recovery of the project costs from FERC before seeking rate recovery from the ACC. See Note 2. In 2012, TEP recorded a regulatory asset of $5 million and UNS Electric recorded a regulatory asset of $0.2 million for the balance deemed probable of recovery.

RESOLUTION OF TEP CONTINGENCIES

Springerville Generating Station Unit 3 Outage

TEP paid Tri-State Generating and Transmission Association, Inc. (Tri-State) $2 million in March 2013 as a result of an outage at Springerville Unit 3 in 2012. TEP accrued the pre-tax loss in July 2012 as a result of not meeting certain availability requirements under the terms of TEP's operating agreement with Tri-State.

ENVIRONMENTAL MATTERS

Environmental Regulation

The Environmental Protection Agency (EPA) limits the amount of sulfur dioxide (SO_2), nitrogen oxide (NOx), particulate matter, mercury and other emissions released into the atmosphere by power plants. TEP may incur added costs to comply with future changes in federal and state environmental laws, regulations, and permit requirements at its power plants. Complying with these changes may reduce operating efficiency. TEP expects to recover the cost of environmental compliance from its ratepayers.

Hazardous Air Pollutant Requirements

The Clean Air Act requires the EPA to develop emission limit standards for hazardous air pollutants that reflect the maximum achievable control technology. In February 2012, the EPA issued final rules to set the standards for the control of mercury emissions and other hazardous air pollutants from power plants.

Navajo

Based on the EPA's standards, Navajo may require mercury and particulate matter emission control equipment by 2015. TEP's share of the estimated capital cost of this equipment is less than $1 million for mercury control and about $43 million if the installation of baghouses to control particulates is necessary. The operator of Navajo is currently analyzing the need for baghouses under various regulatory scenarios, which will be affected by final Best Available Retrofit Technology (BART) rules when issued. TEP expects its share of the annual operating costs for mercury control and baghouses to be less than $1 million each.

San Juan

TEP expects San Juan's current emission controls to be adequate to comply with the EPA's final standards.

Four Corners

Based on the EPA's final standards, Four Corners may require mercury emission control equipment by 2015. TEP's share of the estimated capital cost of this equipment is less than $1 million. TEP expects its share of the annual operating cost of the mercury emission control equipment to be less than $1 million.

Springerville Generating Station

Based on the EPA's final standards, Springerville Generating Station (Springerville) may require mercury emission control equipment by 2015. The estimated capital cost of this equipment for Springerville Units 1 and 2 is about $5 million. TEP expects the annual operating cost of the mercury emission control equipment to be about $3 million.

Sundt Generating Station

TEP expects the final EPA standards will have little effect on capital expenditures at Sundt Generating Station (Sundt).

Regional Haze Rules

The EPA's Regional Haze Rules require emission controls known as BART for certain industrial facilities emitting air pollutants that reduce visibility. The rules call for all states to establish goals and emission reduction strategies for improving visibility in national parks and wilderness areas. States must submit these goals and strategies to the EPA for approval. Because Navajo and Four Corners are located on the Navajo Indian Reservation, they are not subject to state oversight. The EPA oversees regional haze planning for these power plants.

Complying with the EPA's BART findings, and with other future environmental rules, may make it economically impractical to continue operating the Navajo, San Juan, and Four Corners power plants or for individual owners to continue to participate in these power plants. TEP cannot predict the ultimate outcome of these matters.

Navajo

In January 2013, the EPA proposed a BART determination that would require the installation of Selective Catalytic Reduction (SCR) technology on all three units at Navajo by 2023. In July 2013, SRP, along with other stakeholders including impacted government agencies, environmental organizations, and tribal representatives, submitted an agreement to the EPA that would achieve greater NOx emission reductions than the EPA's proposed BART rule. In September 2013, EPA issued a supplemental proposal incorporating the provisions of the agreement as a better-than-BART alternative.

Among other things, the agreement calls for the shut down of one unit or an equivalent reduction in emissions by 2020. The shutdown of one unit will not impact the total amount of energy delivered to TEP from Navajo. Additionally, the remaining Navajo participants would be required to install SCR or an equivalent technology on the remaining two units by 2030. As part of the agreement, the current owners have committed to cease their operation of conventional coal-fired generation at Navajo no later than December 2044. The Navajo Nation can continue operation after 2044 at its election. If SCR technology is ultimately implemented at Navajo, TEP estimates its share of the capital cost will be $42 million. Also, the installation of SCR technology at Navajo could increase the power plant's particulate emissions which may require that baghouses be installed. TEP estimates that its share of the capital expenditure for baghouses would be about $43 million. TEP's share of annual operating costs for SCR and baghouses is estimated at less than $1 million each.

San Juan

In August 2011, the EPA issued a Federal Implementation Plan (FIP) establishing new emission limits for air pollutants at San Juan. These requirements are more stringent than those proposed by the State of New Mexico. The FIP requires the installation of SCR technology with sorbent injection on all four units to reduce NOx and control sulfuric acid emissions by September 2016. TEP estimates its share of the cost to install SCR technology with sorbent injection to be between $180 millionand $200 million. TEP expects its share of the annual operating costs for SCR technology to be approximately $6 million.

In 2011, Public Service Company of New Mexico (PNM) filed a petition for review of, and a motion to stay, the FIP with the United States Court of Appeals for the Tenth Circuit (Tenth Circuit). In addition, the operator filed a request for reconsideration of the rule with the EPA and a request to stay the effectiveness of the rule pending the EPA's reconsideration and review by the Tenth Circuit. The State of New Mexico filed similar motions with the Tenth Circuit and the EPA. Several environmental groups were granted permission to join in opposition to PNM's petition to review in the Tenth Circuit. In addition, WildEarth Guardians filed a separate appeal against the EPA challenging the FIP's five-year implementation schedule. PNM was granted permission to join in opposition to that appeal. In March 2012, the Tenth Circuit denied PNM's and the State of New Mexico's motion for stay. Oral argument on the appeal was heard in October 2012 and the parties are currently awaiting the court's decision. In February 2013, the Tenth Circuit referred the litigation to the Tenth Circuit Mediation Office, which has authority to require the parties to attend mediation conferences to informally resolve issues in the pending appeals.

In February 2013, the State of New Mexico, the EPA, and PNM signed a non-binding agreement that outlines an alternative to the FIP. The terms of the agreement include: the retirement of San Juan Units 2 and 3 by December 31, 2017; the replacement by PNM of those units with non-coal generation sources; and the installation of Selective Non-Catalytic Reduction technology (SNCR) on San Juan Units 1 and 4 by January 2016 or later depending on the timing of EPA approvals. The New Mexico Environmental Department (NMED) prepared a revision to the regional haze SIP incorporating the provisions of the agreement, and in September 2013, the New Mexico Environmental Improvement Board approved the SIP revision. The SIP revision now awaits final EPA approval.

TEP estimates its share of the cost to install SNCR technology on San Juan Unit 1 would be approximately $35 million. TEP's share of incremental annual operating costs for SNCR is estimated at $1 million. TEP owns 340 MW, or 50%, of San Juan Units 1 and 2. At September 30, 2013, the book value of TEP's share of San Juan Unit 2 was $114 million. If Unit 2 is retired early, we expect to request ACC approval to recover, over a reasonable time period, all costs associated with the early closure of the unit. We are evaluating various replacement resources. Any decision regarding early closure and replacement resources will require various actions by third parties as well as UNS Energy board and regulatory approvals. TEP cannot predict the ultimate outcome of this matter.

Four Corners

In August 2012, the EPA finalized the regional haze FIP for Four Corners. The final FIP requires SCR technology to be installed on all five units by 2017. However, the FIP also includes an alternative plan that allows APS to close their wholly-owned Units 1, 2, and 3 and install SCR technology on Units 4 and 5. This option allows the installation of SCR technology to be delayed until July 2018. APS must select which FIP alternative to implement by December 31, 2013. In either case, TEP's estimated share of the capital costs to install SCR technology on Units 4 and 5 is approximately $35 million. TEP's share of incremental annual operating costs for SCR is estimated at $2 million.

Springerville

The BART provisions of the Regional Haze Rules requiring emission control upgrades do not apply to Springerville. Other provisions of the Regional Haze Rule requiring further emission reduction are not likely to impact Springerville operations until after 2018.

Sundt

In July 2013, the EPA rejected the Arizona state implementation plan determination that Sundt Unit 4 is not subject to the BART provisions of the Regional Haze Rule. Under the Regional Haze Rule, Sundt Unit 4 will be required to reduce certain emissions within five years of the final EPA BART determination. The EPA postponed its expected release of a proposed BART requirement for Sundt Unit 4 until December 2013, with a final determination expected in May 2014. While TEP does not agree that Sundt Unit 4 is BART eligible, in anticipation of EPA's proposed BART requirements, TEP has submitted a plan for EPA approval proposing to eliminate coal as a fuel after December 2017.

Greenhouse Gas Regulation

In June 2013, President Obama directed the EPA to move forward with carbon emission regulations for both new and existing fossil-fueled power plants.

In September 2013, the EPA issued a re-proposed rule for new power plants. UNS Energy does not anticipate that a final rule related to new fossil-fueled power plant sources will have a significant impact on operations.

For existing power plants, the President ordered the EPA to:

- propose carbon emission standards by June 1, 2014;
- finalize those standards by June 1, 2015; and
- require states to submit their implementation plans to meet the standards by June 30, 2016.

UNS Energy will continue to work with federal and state regulatory agencies to promote compliance flexibility in the rules impacting existing fossil-fuel fired power plants. We cannot predict the ultimate outcome of these matters.

NOTE 5. DEBT, CREDIT FACILITIES, AND CAPITAL LEASE OBLIGATIONS

We summarize below the significant changes to our debt and capital lease obligations from those reported in our 2012 Annual Report on Form 10-K.

TEP SPRINGERVILLE UNIT 1 CAPITAL LEASE PURCHASE COMMITMENTS

In 2011, TEP and the owner participants of Springerville Unit 1 completed a formal appraisal procedure to determine the fair market value purchase price of Springerville Unit 1 in accordance with the Springerville Unit 1 Leases. The purchase price was determined to be $478 per kW of capacity based on a continuous capacity rating of 387 MW. The appraisal price was challenged, and TEP initiated a proceeding in 2012 seeking judicial confirmation of the results of the appraisal process.

In August 2013, TEP elected to purchase leased interests comprising 24.8% of Springerville Unit 1, representing 96 MW of continuous operating capability, for an aggregate purchase price of $46 million, the appraised value, upon the expiration of the lease term in January 2015.

In October 2013, TEP elected to purchase an additional 10.6% leased interest in Springerville Unit 1, representing 41 MW of continuous operating capability, for $20 million, the appraised value, with the purchase scheduled to occur in December 2014.

Upon close of these lease option purchases, TEP will own 49.5% of Springerville Unit 1, or 192 MW of continuous operating capability. Due to TEP's purchase commitment, TEP and UNS Energy expect to record an increase of approximately $55 millionto both Utility Plant Under Capital Leases and Capital Lease Obligations on their balance sheets, of which $39 million is reflected as of September 30, 2013.

Because the owner participants whose leased interests TEP elected to purchase have agreed to sell their interests for amounts equal to the appraised value, TEP dismissed the legal action associated with the appraisal.

TEP TAX-EXEMPT BONDS ISSUED

In March 2013, the Industrial Development Authority of Pima County, Arizona issued approximately $91 million aggregate principal amount of unsecured tax-exempt industrial development bonds on behalf of TEP. The bonds bear interest at a fixed rate of 4.0%, mature in September 2029, and may be redeemed at par on or after March 1, 2023. The proceeds from the sale of the bonds, together with $0.5 million accrued interest provided by TEP, were deposited with a trustee to retire approximately $91million of 6.375% unsecured tax-exempt bonds in April 2013. TEP's payment of accrued interest was the only cash flow activity since proceeds from the newly-issued bonds were not received nor disbursed by TEP. TEP capitalized approximately $1million in costs related to the issuance of the bonds and will amortize the costs to Interest Expense – Long-Term Debt in the income statement through September 2029, the term of the bonds.

UNS ENERGY'S AND TEP'S CREDIT RATING UPGRADES

In June 2013, the pricing under certain debt agreements improved as a result of an upgrade in the credit ratings of UNS Energy and TEP.

- Under the UNS Energy Credit Agreement, the interest rate decreased from London Interbank Offered Rate (LIBOR) plus 1.75% to LIBOR plus 1.5%;
- Under the TEP Credit Agreement, the interest rate decreased from LIBOR plus 1.125% to LIBOR plus 1.0% ; and the margin rate on the $186 million letter of credit facility decreased from 1.125% to 1.0% ; and
- Under the 2010 TEP Reimbursement Agreement, fees payable on outstanding letters of credit decreased from 1.5% to 1.25% per annum.

TEP MORTGAGE INDENTURE

Prior to November 2013, the TEP Credit Agreement and the 2010 TEP Reimbursement Agreement were secured by $423 million in mortgage bonds issued under the 1992 Mortgage. As a result of TEP's credit rating upgrade, in October 2013, TEP (i) requested $423 million in mortgage bonds be returned to TEP for cancellation, and (ii) discharged the 1992 Mortgage, which had created a lien on and security interest in substantially all of TEP's utility plant assets. TEP's obligations under the TEP Credit Agreement and the 2010 TEP Reimbursement Agreement are now unsecured, which changed the pricing of the following agreements, with pricing tied to credit ratings for short-term borrowings:

- Under the TEP Credit Agreement, the interest rate increased from LIBOR plus 1.0% to LIBOR plus 1.25%; and the margin rate on the $186 million letter of credit facility increased from 1.0% to 1.25%; and
- Under the 2010 TEP Reimbursement Agreement, fees payable on outstanding letters of credit increased from 1.25% to 1.75% per annum.

COVENANT COMPLIANCE

At September 30, 2013, we were in compliance with the terms of our credit agreements, the 2010 TEP Reimbursement Agreement, and UNS Electric's term loan.

NOTE 6. INCOME TAXES

Income tax expense differs from the amount of income tax determined by applying the United States statutory federal income tax rate of 35% to pre-tax income due to the following:

	UNS Energy		TEP	
	Three Months Ended September 30,			
	2013	2012	2013	2012
	Millions of Dollars			
Federal Income Tax Expense at Statutory Rate	$38	$ 29	$36	$ 25
State Income Tax Expense, Net of Federal Deduction	5	3	5	3
Federal/State Tax Credits	(1)	(1)	(1)	(1)
Other	(1)	—	(1)	—
Total Federal and State Income Tax Expense	41	$ 31	$39	$ 27

	UNS Energy		TEP	
	Nine Months Ended September 30,			
	2013	2012	2013	2012
	Millions of Dollars			
Federal Income Tax Expense at Statutory Rate	$ 58	$ 47	$ 48	$ 37
State Income Tax Expense, Net of Federal Deduction	8	6	6	4
Federal/State Tax Credits	(2)	(1)	(2)	(1)
Investment Tax Credit Basis Adjustment – Creation of Regulatory Asset	(11)	—	(11)	—
Other	(1)	(1)	1	(1)
Total Federal and State Income Tax Expense	$ 52	$ 51	$ 42	$ 39

Investment Tax Credit Basis Difference Adjustment

Renewable energy assets are eligible for investment tax credits. We reduce the income tax basis of those qualifying assets by half of the related investment tax credit. Historically, the difference between the income tax basis of the asset and the book basis under GAAP was recorded as a deferred tax liability with an offsetting charge to income tax expense in the year the qualifying asset was placed in service. In June 2013, we recorded a regulatory asset and corresponding reduction of income tax expense of $11 million to recover previously recorded income tax expense through future rates as a result of the 2013 TEP Rate Order. The regulatory asset will be amortized as income tax expense as the qualifying assets are depreciated.

Uncertain Tax Positions

We recognize tax benefits from uncertain tax positions if it is more likely than not that the tax position will be sustained on examination by the taxing authorities. Each uncertain tax position is recognized up to the amount most likely to be sustained on examination and adjusted with changes in facts and circumstances. A reconciliation of the beginning and ending balances of unrecognized tax benefits follows:

	UNS Energy	TEP
	Millions of Dollars	
Unrecognized Tax Benefits at December 31, 2012	$ 30	$ 23
Additions Based on Tax Positions Taken in the Current Year	1	1
Reduction of Positions from Prior Year Based on Tax Authority Ruling	(27)	(22)
Unrecognized Tax Benefits at September 30, 2013	$ 4	$ 2

In February 2013, we received a favorable ruling from the Internal Revenue Service (IRS) allowing us to deduct up-front incentive payments to customers who install renewable energy resources. These customers transfer environmental attributes or RECs associated with their renewable installations to us over the expected life of the contract for an up-front incentive payment based on the generating capacity of their installation. As a result of the IRS ruling in the first quarter of 2013, UNS Energy reduced unrecognized tax benefits by $28 million, and TEP reduced unrecognized tax benefits by $22 million. The changes in tax benefits primarily affected the balance sheets.

The IRS completed its audit of the 2009 and 2010 tax returns in March 2013 resulting in no change to the financial statements.

In April 2013, the IRS provided notice of intent to audit the 2011 tax returns.

Tangible Repairs Regulation

In September 2013, the U.S. Treasury Department released final income tax regulations on the deduction and capitalization of expenditures related to tangible property. These final regulations apply to tax years beginning on or after January 1, 2014. Several of the provisions within the regulations will require a tax accounting method change to be filed with the IRS resulting in a cumulative effect adjustment. Management believes that adoption of these regulations will not result in a material change to plant-related deferred tax liabilities.

NOTE 7. EMPLOYEE BENEFIT PLANS

UNS Energy's net periodic benefit plan cost, comprised primarily of TEP's cost, includes the following components:

	Pension Benefits		Other Retiree Benefits	
	Three Months Ended September 30,			
	2013	2012	2013	2012
	Millions of Dollars			
Service Cost	$ 4	$ 2	$ 1	$ 1
Interest Cost	4	4	—	1
Expected Return on Plan Assets	(5)	(4)	—	—
Actuarial Loss Amortization	2	2	—	—
Net Periodic Benefit Cost	$ 5	$ 4	$ 1	$ 2

	Pension Benefits		Other Retiree Benefits	
	Nine Months Ended September 30,			
	2013	2012	2013	2012
	Millions of Dollars			
Service Cost	$ 10	$ 8	$ 3	$ 2
Interest Cost	11	12	2	2
Expected Return on Plan Assets	(15)	(13)	(1)	—
Actuarial Loss Amortization	7	5	—	—
Net Periodic Benefit Cost	$ 13	$ 12	$ 4	$ 4

NOTE 8. SHARE-BASED COMPENSATION PLANS

RESTRICTED STOCK UNITS

In May 2013, the UNS Energy Compensation Committee granted 8,870 restricted stock units to non-employee directors at a grant date fair value of $48.99 per share. We recognize compensation expense equal to the fair value on the grant date over the one-year vesting period. The grant date fair value was calculated by reducing the grant date share price by the present value of the dividends expected to be paid on the shares during the vesting period. Fully vested but undistributed non-employee director stock unit awards accrue dividend equivalent stock units based on the fair market value of common shares on the date the dividend is paid. We issue UNS Energy Common Stock (Common Stock) for the vested stock units in the January following the year the person is no longer a director.

In February 2013, the UNS Energy Compensation Committee granted 21,560 restricted stock units to certain management employees at a grant date fair value, based on the grant date share price, of $46.23 per share. The restricted stock units vest on the third anniversary of grant and are distributed in shares of Common Stock upon vesting. We recognize compensation expense equal to the fair value on the grant date over the vesting period. These restricted stock units accrue dividend equivalents during the vesting period, which are distributed in shares of Common Stock upon vesting.

PERFORMANCE SHARES

In February 2013, the UNS Energy Compensation Committee granted 43,120 performance share awards to certain management employees. Half of the performance share awards had a grant date fair value, based on a Monte Carlo simulation, of $45.54per share. Those awards will be paid out in Common Stock based on a comparison of UNS Energy's cumulative Total Shareholder Return to the companies included in the Edison Electric Institute Index during the performance period of January 1, 2013 through December 31, 2015. We recognize compensation expense equal to the fair value on the grant date over the vesting period if the requisite service period is fulfilled, whether or not the threshold is achieved. The remaining half had a grant date fair value, based on the grant date share price, of $46.23 per share and will be paid out in Common Stock based on cumulative net income for the three-year period ended December 31, 2015. We recognize compensation expense equal to the fair value on the grant date over the requisite service period only for the awards that ultimately vest. The performance shares vest based on the achievement of these goals by the end of the performance period; any unearned awards are forfeited. Performance shares accrue dividend equivalents during the performance period, which are paid upon vesting.

SHARE-BASED COMPENSATION EXPENSE

UNS Energy and TEP recorded $1 million of share-based compensation expense for the three months ended September 30, 2013 and September 30, 2012. For the nine months ended September 30, 2013, UNS Energy recorded share-based compensation expense of $3 million, $2 million of which related to TEP. For the nine months ended September 30, 2012, UNS Energy and TEP recorded share-based compensation expense of $2 million.

At September 30, 2013, the total unrecognized compensation cost related to non-vested share-based compensation was $4 million, which will be recorded as compensation expense over the remaining vesting periods through February 2016. AtSeptember 30, 2013, 1 million shares were awarded but not yet issued, including performance shares, under the share-based compensation plans.

NOTE 9. UNS ENERGY EARNINGS PER SHARE

We compute basic Earnings Per Share (EPS) by dividing Net Income by the weighted average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could result if outstanding stock options, share-based compensation awards, or UNS Energy's Convertible Senior Notes were exercised or converted into Common Stock. We excluded anti-dilutive stock options and contingently issuable shares from the calculation of diluted EPS. The numerator in calculating diluted EPS is Net Income adjusted for the interest on Convertible Senior Notes (net of tax) that would not be paid if the remaining notes, not yet converted, were converted to Common Stock.

The following table illustrates the effect of dilutive securities on net income and weighted average Common Stock outstanding:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	Thousands of Dollars			
Numerator:				
Net Income	$67,990	$50,664	$113,953	$83,414
Income from Assumed Conversion of Convertible Senior Notes [1]	—	—	—	1,100
Adjusted Net Income Available for Diluted Common Stock Outstanding	$67,990	$50,664	$113,953	$84,514
	Thousands of Shares			
Denominator:				
Weighted Average Shares of Common Stock Outstanding:				
Common Shares Issued	41,472	41,290	41,427	39,835
Fully Vested Deferred Stock Units	178	156	169	148
Total Weighted Average Common Stock Outstanding – Basic	41,650	41,446	41,596	39,983
Effect of Dilutive Securities:				
Convertible Senior Notes [1]	—	—	—	1,417
Options and Stock Issuable Under Share-Based Compensation Plans	378	417	345	319
Total Weighted Average Common Stock Outstanding – Diluted	42,028	41,863	41,941	41,719

[1] In 2012, the Convertible Senior Notes were converted to Common Stock or redeemed for cash.

We excluded the following outstanding stock options, with an exercise price above market, and contingently issuable shares from our diluted EPS computation as their effect would be anti-dilutive:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	Thousands of Shares			
Stock Options	—	—	—	67
Restricted Stock Units	—	—	8	—
Total Anti-Dilutive Shares Excluded from the Diluted EPS Computation	—	—	8	67

NOTE 10. SUPPLEMENTAL CASH FLOW INFORMATION

A reconciliation of Net Income to Net Cash Flows from Operating Activities follows:

	UNS Energy	
	Nine Months Ended September 30,	
	2013	2012
	Thousands of Dollars	
Net Income	$113,953	$ 83,414
Adjustments to Reconcile Net Income		
To Net Cash Flows from Operating Activities		
Depreciation Expense	111,175	105,319
Amortization Expense	21,600	26,845
Depreciation and Amortization Recorded to Fuel and Operations and Maintenance Expense	5,399	4,911
Amortization of Deferred Debt-Related Costs Included in Interest Expense	2,280	2,250
Provision for Retail Customer Bad Debts	1,703	2,017
Use of RECs for Compliance	12,999	4,017
Deferred Income Taxes	77,962	63,057
Investment Tax Credit Basis Adjustment – Creation of Regulatory Asset	(11,039)	—
Pension and Retiree Expense	17,087	16,391
Pension and Retiree Funding	(27,602)	(23,649)
Share-Based Compensation Expense	2,810	1,952
Allowance for Equity Funds Used During Construction	(4,145)	(2,708)
Increase (Decrease) to Reflect PPFAC/PGA Recovery	(6,814)	29,730
PPFAC Reduction – 2013 TEP Rate Order	3,000	—
Liquidated Damages for Springerville Unit 3 Outage	—	1,921
Changes in Assets and Liabilities which Provided (Used)		
Cash Exclusive of Changes Shown Separately		
Accounts Receivable	(32,883)	(28,686)
Materials and Fuel Inventory	14,839	(33,038)
Accounts Payable	(18,497)	(5,220)
Income Taxes	(15,847)	(11,738)
Interest Accrued	(2,137)	(1,551)
Taxes Other Than Income Taxes	18,718	16,478
Other	20,473	16,426
Net Cash Flows – Operating Activities	$305,034	$268,138

	TEP	
	Nine Months Ended September 30,	
	2013	2012
	Thousands of Dollars	
Net Income	$ 96,433	$ 65,018
Adjustments to Reconcile Net Income		
To Net Cash Flows from Operating Activities		
Depreciation Expense	87,729	82,656
Amortization Expense	24,393	29,621
Depreciation and Amortization Recorded to Fuel and Operations and Maintenance Expense	4,602	3,922
Amortization of Deferred Debt-Related Costs Included in Interest Expense	1,831	1,628
Provision for Retail Customer Bad Debts	1,315	1,348
Use of RECs for Compliance	11,766	3,324
Deferred Income Taxes	64,132	51,638
Investment Tax Credit Basis Adjustment – Creation of Regulatory Asset	(10,751)	—
Pension and Retiree Expense	14,909	14,466
Pension and Retiree Funding	(26,118)	(20,989)
Share-Based Compensation Expense	2,239	1,540
Allowance for Equity Funds Used During Construction	(2,923)	(2,265)
Increase (Decrease) to Reflect PPFAC Recovery	(5,079)	25,150
PPFAC Reduction – 2013 TEP Rate Order	3,000	—
Liquidated Damages for Springerville Unit 3 Outage	—	1,921
Changes in Assets and Liabilities which Provided (Used)		
Cash Exclusive of Changes Shown Separately		
Accounts Receivable	(42,542)	(44,269)
Materials and Fuel Inventory	14,955	(32,448)
Accounts Payable	(8,678)	4,977
Income Taxes	(10,681)	(11,424)
Interest Accrued	1,008	2,729
Taxes Other Than Income Taxes	17,405	16,710
Other	15,234	11,898
Net Cash Flows – Operating Activities	$254,179	$207,151

Non-Cash Transactions

In August 2013, TEP recorded an increase of $39 million to both Utility Plant Under Capital Leases and Capital Lease Obligations due to TEP's commitment to purchase leased interests in January 2015. See Note 5.

In March 2013, TEP issued $91 million of tax-exempt bonds and used the proceeds to redeem debt using a trustee. Since the cash flowed through a trust account, the issuance and redemption of debt resulted in a non-cash transaction. See Note 5.

In September 2012, TEP declared a $30 million dividend to UNS Energy which was paid in October 2012.

In the first nine months of 2012, UNS Energy converted $147 million of the previously outstanding $150 million Convertible Senior Notes into Common Stock, resulting in non-cash transactions.

In the first nine months of 2012, TEP's redemption of $193 million of tax-exempt bonds resulted in a non-cash transaction.

NOTE 11. FAIR VALUE MEASUREMENTS AND DERIVATIVE INSTRUMENTS

We categorize our assets and liabilities accounted for at fair value into the three-level hierarchy based on inputs used to determine the fair value. Level 1 inputs are unadjusted quoted prices for identical assets or liabilities in an active market. Level 2 inputs include quoted prices for similar assets or liabilities, quoted prices in non-active markets, and pricing models whose inputs are observable, directly or indirectly. Level 3 inputs are unobservable and supported by little or no market activity.

FINANCIAL INSTRUMENTS NOT CARRIED AT FAIR VALUE

The fair value of a financial instrument is the market price to sell an asset or transfer a liability at the measurement date. We use the following methods and assumptions for estimating the fair value of our financial instruments:

- The carrying amounts of our current assets, current liabilities, including current maturities of long-term debt, and amounts outstanding under our credit agreements approximate the fair values due to the short-term nature of these financial instruments. These items have been excluded from the table below.
- For Investment in Lease Debt, we calculated the present value of remaining cash flows using current market rates for instruments with similar characteristics such as credit rating and time-to-maturity. We also incorporated the impact of counterparty credit risk using market credit default swap data. TEP's Investment in Lease Debt matured in January 2013.
- For Investment in Lease Equity, we estimate the price at which an investor would realize a target internal rate of return. Our estimates include: the mix of debt and equity an investor would use to finance the purchase; the cost of debt; the required return on equity; and income tax rates. The estimate assumes a residual value based on an appraisal of Springerville Unit 1 conducted in 2011.
- For Long-Term Debt, we use quoted market prices, when available, or calculate the present value of remaining cash flows at the balance sheet date. When calculating present value, we use current market rates for bonds with similar characteristics such as credit rating and time-to-maturity. We consider the principal amounts of variable rate debt outstanding to be reasonable estimates of the fair value. We also incorporate the impact of our own credit risk using a credit default swap rate.

The use of different estimation methods and/or market assumptions may yield different estimated fair value amounts. The carrying values recorded on the balance sheets and the estimated fair values of our financial instruments include the following:

		September 30, 2013		December 31, 2012	
	Fair Value Hierarchy	Carrying Value	Fair Value	Carrying Value	Fair Value
		Millions of Dollars			
Assets:					
TEP Investment in Lease Debt	Level 2	$ —	$ —	$ 9	$ 9
TEP Investment in Lease Equity	Level 3	36	24	36	23
Liabilities:					
Long-Term Debt					
UNS Energy	Level 2	1,506	1,522	1,498	1,583
TEP	Level 2	1,224	1,215	1,223	1,271

FINANCIAL INSTRUMENTS MEASURED AT FAIR VALUE ON A RECURRING BASIS

The following tables present, by level within the fair value hierarchy, UNS Energy's and TEP's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

	UNS Energy					
	Total	Level 1	Level 2	Level 3	Counterparty Netting of Energy Contracts Not Offset on the Balance Sheets (5)	Net Amount
	September 30, 2013 Millions of Dollars					
Assets						
Cash Equivalents (1)	$ 31	$ 31	$—	$—	$—	$ 31
Restricted Cash (1)	2	2	—	—	—	2
Rabbi Trust Investments (2)	21	—	21	—	—	21
Energy Contracts – Regulatory Recovery (3)	2	—	1	1	(2)	—
Total Assets	56	33	22	1	(2)	54
Liabilities						
Energy Contracts – Regulatory Recovery (3)	(11)	—	(5)	(6)	2	(9)
Energy Contracts – Cash Flow Hedge (3)	(1)	—	—	(1)	—	(1)
Interest Rate Swaps (4)	(8)	—	(8)	—	—	(8)
Total Liabilities	(20)	—	(13)	(7)	2	(18)
Net Total Assets (Liabilities)	$ 36	$ 33	$ 9	$ (6)	$—	$ 36

	UNS Energy					
	Total	Level 1	Level 2	Level 3	Counterparty Netting of Energy Contracts Not Offset on the Balance Sheets (5)	Net Amount
	December 31, 2012 Millions of Dollars					
Assets						
Cash Equivalents (1)	$ 20	$ 20	$—	$—	$—	$ 20
Restricted Cash (1)	7	7	—	—	—	7
Rabbi Trust Investments (2)	19	—	19	—	—	19
Energy Contracts – Regulatory Recovery (3)	7	—	2	5	(5)	2
Total Assets	53	27	21	5	(5)	48
Liabilities						
Energy Contracts – Regulatory Recovery (3)	(15)	—	(7)	(8)	5	(10)
Energy Contracts – Cash Flow Hedge (3)	(2)	—	—	(2)	—	(2)
Interest Rate Swaps (4)	(10)	—	(10)	—	—	(10)
Total Liabilities	(27)	—	(17)	(10)	5	(22)
Net Total Assets (Liabilities)	$ 26	$ 27	$ 4	$ (5)	$—	$ 26

	TEP					
	Total	Level 1	Level 2	Level 3	Counterparty Netting of Energy Contracts Not Offset on the Balance Sheets (5)	Net Amount
	September 30, 2013 Millions of Dollars					
Assets						
Cash Equivalents (1)	$ 15	$ 15	$—	$—	$—	$ 15
Restricted Cash (1)	2	2	—	—	—	2
Rabbi Trust Investments (2)	21	—	21	—	—	21
Energy Contracts – Regulatory Recovery (3)	1	—	1	—	(1)	—
Total Assets	39	17	22	—	(1)	38
Liabilities						
Energy Contracts – Regulatory Recovery (3)	(3)	—	(2)	(1)	1	(2)
Energy Contracts – Cash Flow Hedge (3)	(1)	—	—	(1)	—	(1)
Interest Rate Swaps (4)	(8)	—	(8)	—	—	(8)
Total Liabilities	(12)	—	(10)	(2)	1	(11)
Net Total Assets (Liabilities)	$ 27	$ 17	$ 12	$ (2)	$—	$ 27

	TEP					
	Total	Level 1	Level 2	Level 3	Counterparty Netting of Energy Contracts Not Offset on the Balance Sheets [5]	Net Amount
	December 31, 2012 Millions of Dollars					
Assets						
Cash Equivalents [1]	$ 1	$ 1	$—	$—	$—	$ 1
Restricted Cash [1]	7	7	—	—	—	7
Rabbi Trust Investments [2]	19	—	19	—	—	19
Energy Contracts – Regulatory Recovery [3]	3	—	1	2	(1)	2
Total Assets	30	8	20	2	(1)	29
Liabilities						
Energy Contracts – Regulatory Recovery [3]	(3)	—	(3)	—	1	(2)
Energy Contracts – Cash Flow Hedge [3]	(2)	—	—	(2)	—	(2)
Interest Rate Swaps [4]	(10)	—	(10)	—	—	(10)
Total Liabilities	(15)	—	(13)	(2)	1	(14)
Net Total Assets (Liabilities)	$ 15	$ 8	$ 7	$—	$—	$ 15

(1) Cash Equivalents and Restricted Cash represent amounts held in money market funds and certificates of deposit valued at cost, including interest. Cash Equivalents are included in Cash and Cash Equivalents on the balance sheets. Restricted Cash is included in Investments and Other Property – Other on the balance sheets.

(2) Rabbi Trust Investments include amounts related to deferred compensation and Supplement Executive Retirement Plan (SERP) benefits held in mutual and money market funds valued at quoted prices traded in active markets. These investments are included in Investments and Other Property – Other on the balance sheets.

(3) Energy Contracts include gas swap agreements (Level 2), power options (Level 2), gas options (Level 3), forward power purchase and sales contracts (Level 3), and forward power purchase contracts indexed to gas (Level 3), entered into to reduce exposure to energy price risk. These contracts are included in Derivative Instruments on the UNS Energy and TEP balance sheets. The valuation techniques are described below.

(4) Interest Rate Swaps are valued based on the 3-month or 6-month LIBOR index or the Securities Industry and Financial Markets Association municipal swap index. These interest rate swaps are included in Derivative Instruments on the balance sheets.

(5) All energy contracts are subject to legally enforceable master netting arrangements to mitigate credit risk. We have presented the effect of offset by counterparty; however, we present derivatives on a gross basis on the balance sheets.

DERIVATIVE INSTRUMENTS

Regulatory Recovery

We are exposed to energy price risk associated with our gas and purchased power requirements. We reduce our energy price risk through a variety of derivative and non-derivative instruments. The objectives for entering into such contracts include: creating price stability; meeting load and reserve requirements; and reducing exposure to price volatility that may result from delayed recovery under the PPFAC or PGA. See Note 2.

We primarily apply the market approach for recurring fair value measurements. When we have observable inputs for substantially the full term of the asset or liability or use quoted prices in an inactive market, we categorize the instrument in Level 2. We categorize derivatives in Level 3 when we use an aggregate pricing service or published prices that represent a consensus reporting of multiple brokers.

For both power and gas prices we obtain quotes from brokers, major market participants, exchanges, or industry publications and rely on our own price experience from active transactions in the market. We primarily use one set of quotations each for power and for gas and then validate those prices using other sources. We believe that the market information provided is reflective of market conditions as of the time and date indicated.

Published prices for energy derivative contracts may not be available due to the nature of contract delivery terms such as non-standard time blocks and non-standard delivery points. In these cases, we apply adjustments based on historical price curve relationships, transmission, and line losses.

We estimate the fair value of our gas options using a Black-Scholes-Merton option pricing model which includes inputs such as implied volatility, interest rates, and forward price curves. Beginning in the third quarter of 2013, the fair value of our power options is based on contractually specified option premiums instead of the Black-Scholes-Merton option pricing model because the needed inputs are no longer available. Based on the change, we transferred the power options out of Level 3 and in to Level 2 at the end of third quarter of 2013. The amount transferred was less than $0.5 million. We record transfers between levels in the fair value hierarchy at the end of the reporting period. There were no other transfers between levels in the periods presented.

We also consider the impact of counterparty credit risk using current and historical default and recovery rates, as well as our own credit risk using credit default swap data.

Our assessments of the significance of a particular input to the fair value measurements require judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. We review the assumptions underlying our contracts monthly.

Cash Flow Hedges

We enter into interest rate swaps to mitigate the exposure to volatility in variable interest rates on debt. These swap agreements expire through January 2020. We also have a power purchase swap to hedge the cash flow risk associated with a long-term power supply agreement. This swap agreement expires in September 2015. The after-tax unrealized gains and losses on cash flow hedge activities and amounts reclassified to earnings are reported in the statements of other comprehensive income and Note 12. The loss expected to be reclassified to earnings within the next twelve months is estimated to be $4 million.

Financial Impact of Energy Contracts

We record unrealized gains and losses on energy contracts that are recoverable through the PPFAC or PGA on the balance sheets as a regulatory asset or a regulatory liability rather than reporting the transaction in the income statements or in the statements of other comprehensive income, as shown in following tables:

	UNS Energy		TEP	
	Three Months Ended September 30,			
	2013	2012	2013	2012
	Millions of Dollars			
Increase (Decrease) to Regulatory Assets/Liabilities	$1	$(12)	$1	$(6)

	UNS Energy		TEP	
	Nine Months Ended September 30,			
	2013	2012	2013	2012
	Millions of Dollars			
Increase (Decrease) to Regulatory Assets/Liabilities	$—	$(20)	$2	$(7)

Realized gains and losses on settled contracts are fully recoverable through the PPFAC or PGA. At September 30, 2013, UNS Energy and TEP have energy contracts that will settle through the third quarter of 2016.

Derivative Volumes

The volumes associated with our energy contracts were as follows:

	UNS Energy		TEP	
	September 30, 2013	December 31, 2012	September 30, 2013	December 31, 2012
Power Contracts GWh	1,819	2,228	856	820
Gas Contracts GBtu	29,022	17,851	8,504	7,958

Level 3 Fair Value Measurements

The following table provides quantitative information regarding significant unobservable inputs in UNS Energy's Level 3 fair value measurements:

		Fair Value at September 30, 2013			
	Valuation Approach	Assets	Liabilities	Unobservable Inputs	Range of Unobservable Input
		Millions of Dollars			
Forward Contracts (1)	Market approach	$1	$(7)	Market price per MWh	$23.00 – $48.00

(1) TEP comprises $2 million of the forward contract liabilities.

Our exposure to risk resulting from changes in the unobservable inputs identified above is mitigated as we report the change in fair value of energy contract derivatives as a regulatory asset or a regulatory liability recoverable through the PPFAC or PGA mechanisms, or as a component of other comprehensive income, rather than in the income statement.

The following tables present a reconciliation of changes in the fair value of assets and liabilities classified as Level 3 in the fair value hierarchy:

	Three Months Ended September 30, 2013	
	UNS Energy	TEP
	Millions of Dollars	
Balances at June 30, 2013	$(5)	$ (1)
Realized/Unrealized Gains/(Losses) Recorded to:		
Net Regulatory Assets/Liabilities – Derivative Instruments	(3)	(1)
Settlements	2	—
Balances at September 30, 2013	$(6)	$ (2)
Total Gains/(Losses) Attributable to the Change in Unrealized Gains/(Losses) Relating to Assets/Liabilities Still Held at the End of the Period	$(2)	$—

	Nine Months Ended September 30, 2013	
	UNS Energy	TEP
	Millions of Dollars	
Balances at December 31, 2012	$(5)	$—
Realized/Unrealized Gains/(Losses) Recorded to:		
Net Regulatory Assets/Liabilities – Derivative Instruments	(4)	(2)
Settlements	3	—
Balances at September 30, 2013	$(6)	$ (2)
Total Gains/(Losses) Attributable to the Change in Unrealized Gains/(Losses) Relating to Assets/Liabilities Still Held at the End of the Period	$(5)	$ (1)

	Three Months Ended September 30, 2012	
	UNS Energy	TEP
	Millions of Dollars	
Balances at June 30, 2012	$ (7)	$ (1)
Realized/Unrealized Gains/(Losses) Recorded to:		
Net Regulatory Assets/Liabilities – Derivative Instruments	—	1
Settlements	1	—
Balances at September 30, 2012	$ (6)	$—
Total Gains/(Losses) Attributable to the Change in Unrealized Gains/(Losses) Relating to Assets/Liabilities Still Held at the End of the Period	$—	$—

	Nine Months Ended September 30, 2012	
	UNS Energy	TEP
	Millions of Dollars	
Balances at December 31, 2011	$(10)	$—
Realized/Unrealized Gains/(Losses) Recorded to:		
Net Regulatory Assets/Liabilities – Derivative Instruments	(4)	—
Settlements	8	—
Balances at September 30, 2012	$ (6)	$—
Total Gains/(Losses) Attributable to the Change in Unrealized Gains/(Losses) Relating to Assets/Liabilities Still Held at the End of the Period	$ (1)	$—

CREDIT RISK

We consider the effect of counterparty credit risk in determining the fair value of derivative instruments that are in a net asset position after incorporating collateral posted by counterparties and allocate the credit risk adjustment to individual contracts. We also consider the impact of our own credit risk after considering collateral posted on instruments that are in a net liability position and allocate the credit risk adjustment to all individual contracts. The impact of counterparty credit risk and our own credit risk on the fair value of derivative contracts was less than $0.5 million at September 30, 2013 and at December 31, 2012.

Material adverse changes could trigger credit risk-related contingent features. At September 30, 2013, the fair value of derivative instruments in a net liability position under contracts with credit risk-related contingent features was $35 million for UNS Energy and $13 million for TEP. The additional collateral to be posted if credit-risk contingent features were triggered would be $35 million for UNS Energy and $13 million for TEP.

NOTE 12. CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME BY COMPONENT

The realized changes in AOCI by component are as follows:

Details About Accumulated Other Comprehensive Income Components	Amount Reclassified from Other Comprehensive Income		Affected Line Item in the Income Statement
	UNS Energy	TEP	
	Three Months Ended September 30, 2013		
	Thousands of Dollars		
Realized Losses on Cash Flow Hedges			
Interest Rate Swaps – Debt	$(350)	$(296)	Interest Expense Long-Term Debt
Interest Rate Swaps – Capital Leases	(612)	(612)	Interest Expense Capital Leases
Commodity Contracts	(556)	(556)	Purchased Energy/Purchased Power
Tax Benefit	601	579	
Realized Losses on Cash Flow Hedges, Net of Taxes	(917)	(885)	
Amortization of SERP and Defined Benefit Plans			
Prior Service Costs	(110)	(110)	Other Expense
Tax Benefit	42	42	
Amortization, Net of Taxes	(68)	(68)	
Total Reclassifications from Other Comprehensive Income for the Period	$(985)	$(953)	

Details About Accumulated Other Comprehensive Income Components	Amount Reclassified from Other Comprehensive Income		Affected Line Item in the Income Statement
	UNS Energy	TEP	
	Nine Months Ended September 30, 2013		
	Thousands of Dollars		
Realized Losses on Cash Flow Hedges			
Interest Rate Swaps – Debt	$(1,026)	$ (871)	Interest Expense Long-Term Debt
Interest Rate Swaps – Capital Leases	(1,820)	(1,820)	Interest Expense Capital Leases
Commodity Contracts	(747)	(747)	Purchased Energy/Purchased Power
Tax Benefit	1,420	1,360	
Realized Losses on Cash Flow Hedges, Net of Taxes	(2,173)	(2,078)	
Amortization of SERP and Defined Benefit Plans			
Prior Service Costs	(332)	(332)	Other Expense
Tax Benefit	127	127	
Amortization, Net of Taxes	(205)	(205)	
Total Reclassifications from Other Comprehensive Income for the Period	$(2,378)	$(2,283)	

NOTE 13. POTENTIAL PURCHASE OF GAS-FIRED GENERATION FACILITY

In August 2013, TEP entered into exclusive negotiations with Entegra Power Group LLC (Entegra) to purchase Unit 3 of the Gila River Generating Station (Gila River Unit 3) located in Gila Bend, Arizona. Gila River Unit 3 is a gas-fired combined cycle unit with a nominal capacity rating of 550 MW. Although there can be no assurance that TEP and Entegra will reach agreement on TEP's purchase of Gila River Unit 3, TEP anticipates that, if such an agreement is reached, definitive purchase and sale agreements would be executed prior to year-end 2013. TEP further anticipates any such purchase would close by year-end 2014 and would be subject to, among other things, the receipt of required regulatory approvals. UNS Electric may purchase up to 150 MW of Gila River Unit 3, while TEP would purchase the remaining capacity.

NOTE 14. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

The Financial Accounting Standards Board (FASB) issued guidance for the recognition, measurement, and disclosure of certain obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. On adoption, an entity would recognize and disclose in the financial statements its obligation from a joint and several liability arrangement as the sum of the amount the entity agreed with its co-obligors that it will pay, and any additional amount the entity expects to pay on behalf of its co-obligors. This guidance will be effective in the first quarter of 2014. We do not expect the adoption of this guidance to have a material impact on our financial condition, results of operations, or cash flows.

The FASB issued guidance which permits an entity to designate the Federal Funds Rate (the interest rate at which depository institutions lend balances to each other overnight) as a benchmark interest rate for fair value and cash flow hedges. Prior to this guidance, only interest rates on direct treasury obligations of the U.S. Government and the LIBOR were considered benchmark interest rates in the U.S. This guidance is effective immediately, and can be applied prospectively for qualifying new or redesignated hedging relationships entered into on or after July 17, 2013. We have not entered into any new cash flow or fair value hedges since the effective date of this guidance. We do not expect this guidance to have a material impact on our financial condition, results of operations, or cash flows.

The FASB issued new guidance on the financial statement presentation of unrecognized tax benefits when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. We will be required to comply with the guidance on a prospective basis beginning in the first quarter of 2014. Although adoption of this new guidance may impact how such items are classified on our balance sheets, we do not expect such change to be material. In addition, there will be no changes in the presentations of our other financial statements.

Unaudited Pro forma Consolidated Financial Statements

Fortis Inc.

As at and for the nine months ended September 30, 2013 and for the year ended December 31, 2012

FOREWORD

UNAUDITED *PRO FORMA* CONSOLIDATED FINANCIAL STATEMENTS

The following unaudited *pro forma* consolidated financial statements give effect to the proposed acquisition (the "Proposed Acquisition") by Fortis Inc. of UNS Energy Corporation and its subsidiaries (collectively, "UNS Energy") under the purchase method of accounting. The unaudited *pro forma* consolidated balance sheet gives effect to the Proposed Acquisition as if it had closed on September 30, 2013. The unaudited *pro forma* consolidated statements of earnings for the nine-months ended September 30, 2013 and for the year ended December 31, 2012 give effect to the Proposed Acquisition as if it had closed on January 1, 2012.

The unaudited *pro forma* consolidated financial statements are presented for illustrative purposes only. The *pro forma* adjustments are based upon available information and certain assumptions that we believe are reasonable in the circumstances, as described in the notes to the unaudited *pro forma* consolidated financial statements.

UNS Energy, formerly UniSource Energy Corporation, is a utility services holding company engaged, through its subsidiaries, in the electric generation and energy delivery business. The unaudited *pro forma* consolidated financial statements are based on UNS Energy's consolidated financial statements as at and for the nine-months ended September 30, 2013 and for the year ended December 31, 2012.

The *pro forma* information presented, including allocation of purchase price, is based on preliminary estimates of fair values of assets acquired and liabilities assumed, available information and assumptions and may be revised as additional information becomes available. The actual adjustments to the consolidated financial statements upon the closing of the Proposed Acquisition will depend on a number of factors, including additional information available and the net assets of UNS Energy on the closing date of the Proposed Acquisition. Therefore, the actual adjustments will differ from the *pro forma* adjustments, and the differences may be material. For example, the final purchase price allocation is dependent on, among other things, the finalization of asset and liability valuations. A final determination of these fair values will reflect an independent third-party valuation. This final valuation will be based on the actual net tangible and intangible assets and liabilities of UNS Energy that exist as of the closing date of the Proposed Acquisition. Any final adjustment may change the allocation of purchase price, which could affect the fair value assigned to the assets and liabilities and could result in a change to the unaudited *pro forma* consolidated financial statements, including a change to goodwill.

FORTIS INC.

PRO FORMA CONSOLIDATED BALANCE SHEET
AS AT SEPTEMBER 30, 2013
(Unaudited)
(In millions of Canadian dollars)

	Fortis Inc.	UNS Energy	*Note*	*Pro forma* adjustments	*Pro forma* consolidated balance sheet
ASSETS					
Current assets					
Cash and cash equivalents	$ 155	$ 75	3[b]	$(2,606)	**$ 230**
			3[c]	1,800	
			3[c]	(72)	
			3[d]	922	
			3[d]	(14)	
			3[e]	(30)	
Accounts receivable	523	183		—	**706**
Prepaid expenses	53	28		—	**81**
Inventories	172	138		—	**310**
Regulatory assets	146	54		—	**200**
Deferred income taxes	34	69		—	**103**
	1,083	547		—	**1,630**
Other assets	233	96	3[d]	14	**343**
Regulatory assets	1,825	207		—	**2,032**
Deferred income taxes	4	—	3[c]	21	**26**
			3[e]	1	
Utility capital assets	11,350	3,573		—	**14,923**
Non-utility capital assets	655	—		—	**655**
Intangibles assets	356	—		—	**356**
Goodwill	2,064	—	3[b]	1,439	**3,503**
	$17,570	$4,423		$ 1,475	**$23,468**
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities					
Short-term borrowings	$ 111	$ 24		$ —	**$ 135**
Accounts payable and other current liabilities	847	265	3[e]	(5)	**1,107**
Regulatory liabilities	108	59		—	**167**
Current installments of long-term debt	369	—		—	**369**
Current installments of capital lease and finance obligations	7	174		—	**181**
Deferred income taxes	9	—		—	**9**
	1,451	522		(5)	**1,968**
Other Liabilities	808	244		—	**1,052**
Regulatory liabilities	804	307		—	**1,111**
Deferred income taxes	1,064	497		—	**1,561**
Long-term debt	6,750	1,552	3[d]	922	**9,224**
Capital lease and finance obligations	421	134		—	**555**
	11,298	3,256		917	**15,471**
Shareholders' equity					
Common shares	3,760	915	3[g]	(915)	**5,509**
			3[c]	1,800	
			3[c]	(72)	
			3[c]	21	
Preference shares	1,229	—		—	**1,229**
Additional paid-in capital	16	—		—	**16**
Accumulated other comprehensive loss	(101)	(8)	3[g]	8	**(101)**
Retained earnings	1,013	260	3[g]	(260)	**989**
			3[e]	(30)	
			3[e]	6	
	5,917	1,167		558	**7,642**
Non-controlling interests	355	—		—	**355**
	6,272	1,167		558	**7,997**
	$17,570	$4,423		$ 1,475	**$23,468**

See the accompanying notes to the unaudited pro forma consolidated financial statements, which are integral part of these statements.

FORTIS INC.

PRO FORMA CONSOLIDATED STATEMENT OF EARNINGS FOR THE NINE-MONTHS ENDED SEPTEMBER 30, 2013

(Unaudited)

(In millions of Canadian dollars, except for per share amounts)

	Fortis Inc.	UNS Energy	*Note*	*Pro forma* adjustments	*Pro forma* consolidated statement of earnings
Revenue	$2,874	$1,161		$ —	**$4,035**
Expenses					
Energy supply costs	1,143	462		—	**1,605**
Operating	726	327		—	**1,053**
Depreciation and amortization	400	136		—	**536**
	2,269	925		—	**3,194**
Operating income	605	236		—	**841**
Other income (expenses)	(36)	6		—	**(30)**
Finance charges	284	72	3[d]	41	**398**
			3[d]	1	
Earnings before income taxes and extraordinary item	285	170		(42)	**413**
Income tax expense	3	53	3[d]	(12)	**36**
			3[f]	(8)	
Net earnings before extraordinary item	282	117		(22)	**377**
Extraordinary gain net of tax	22	—		—	**22**
Net earnings	$ 304	$ 117		$ (22)	**$ 399**
Net earnings attributable to:					
Non-controlling interests	$ 7	$ —		$ —	**$ 7**
Preference equity shareholders	44	—		—	**44**
Common equity shareholders	253	117		(22)	**348**
	$ 304	$ 117		$ (22)	**$ 399**
Earnings attributable to common equity shareholders, basic	$ 253				**$ 348**
Effect of potential dilutive securities: preference shares	11				**11**
Anti-dilutive impact: preference shares	(11)				**(11)**
Earnings attributable to common equity shareholders, diluted	$ 253				**$ 348**
Weighted average common shares outstanding (#, millions)					
Basic	199.1		3[h]	58.6	**257.7**
Diluted	199.8		3[h]	58.6	**258.4**
Earnings per common share before extraordinary item					
Basic	$ 1.16				**$ 1.26**
Diluted	$ 1.16				**$ 1.26**
Earnings per common share					
Basic	$ 1.27				**$ 1.35**
Diluted	$ 1.27				**$ 1.35**

See the accompanying notes to the unaudited pro forma consolidated financial statements, which are integral part of these statements.

FORTIS INC.

PRO FORMA CONSOLIDATED STATEMENT OF EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2012

(Unaudited)

(In millions of Canadian dollars, except for per share amounts)

	Fortis Inc.	UNS Energy	*Note*	*Pro forma* adjustments	*Pro forma* consolidated statement of earnings
Revenue	$3,654	$1,461		$ —	**$5,115**
Expenses					
Energy supply costs	1,522	599		—	**2,121**
Operating	868	434		—	**1,302**
Depreciation and amortization	470	177		—	**647**
	2,860	1,210		—	**4,070**
Operating income	794	251		—	**1,045**
Other income	4	—		—	**4**
Finance charges	366	105	3[d]	55	**527**
			3[d]	1	
Earnings before income taxes	432	146		(56)	**522**
Income tax expense	61	56	3[d]	(16)	**90**
			3[f]	(11)	
Net earnings	$ 371	$ 90		$ (29)	**$ 432**
Net earnings attributable to:					
Non-controlling interests	$ 9	$ —		$ —	**$ 9**
Preference equity shareholders	47	—		—	**47**
Common equity shareholders	315	90		(29)	**376**
	$ 371	$ 90		$ (29)	**$ 432**
Earnings attributable to common equity shareholders, basic	$ 315				**$ 376**
Effect of potential dilutive securities: preference shares	17				**17**
Anti-dilutive impact: preference shares	(7)				**(7)**
Earnings attributable to common equity shareholders, diluted	$ 325				**$ 386**
Weighted average common shares outstanding (#, millions)					
Basic	190.0		3[h]	58.6	**248.6**
Diluted	197.2		3[h]	58.6	**255.8**
Earnings per common share					
Basic	$ 1.66				**$ 1.51**
Diluted	$ 1.65				**$ 1.51**

See the accompanying notes to the unaudited pro forma consolidated financial statements, which are integral part of these statements.

Notes to Unaudited *Pro Forma* Consolidated Financial Statements
As at and for the nine-months ended September 30, 2013 and for the year ended December 31, 2012
(in millions of Canadian dollars, unless otherwise stated)

1. BASIS OF PRESENTATION

The accompanying unaudited *pro forma* consolidated financial statements give effect to the proposed acquisition ("Proposed Acquisition") by Fortis Inc. ("Fortis" or the "Corporation") of UNS Energy Corporation and its subsidiaries (collectively, "UNS Energy") as described in the short form prospectus dated December 20, 2013 (the "Prospectus"). The accompanying unaudited *pro forma* consolidated financial statements have been prepared by management of Fortis and are derived from the unaudited and audited consolidated financial statements of Fortis as at and for the nine-months ended September 30, 2013 and for the year ended December 31, 2012, respectively, and the unaudited and audited consolidated financial statements of UNS Energy as at and for the nine-months ended September 30, 2013 and for the year ended December 31, 2012, respectively.

The accompanying unaudited *pro forma* consolidated financial statements utilize accounting policies that are consistent with those disclosed in the Corporation's audited consolidated financial statements and were prepared in accordance with accounting principles generally accepted in the United States.

The Proposed Acquisition has been accounted for using the purchase method. The purchase price is primarily based upon the regulated assets at the date of closing. Based on the purchase price calculation as detailed in the merger agreement dated December 11, 2013, the estimated net purchase price for the equity of UNS Energy is approximately $2.6 billion (Note 3[a]).

The accompanying unaudited *pro forma* consolidated balance sheet and unaudited *pro forma* consolidated statements of earnings reflect the Proposed Acquisition effected on September 30, 2013 and January 1, 2012, respectively. The accompanying unaudited *pro forma* consolidated financial statements are not necessarily indicative of the results that would have been achieved if the transactions reflected therein had been completed on the dates indicated or the results which may be obtained in the future. For instance, the actual purchase price allocation will reflect the fair value, at the purchase date, of the assets acquired and liabilities assumed based upon the Corporation's evaluation of such assets and liabilities following the closing of the Proposed Acquisition and, accordingly, the final purchase price allocation, as it relates principally to goodwill, may differ materially from the preliminary allocation reflected herein.

The accompanying unaudited *pro forma* consolidated financial statements should be read in conjunction with the description of the Proposed Acquisition and the financing thereof provided in the Prospectus; the audited and unaudited consolidated financial statements of UNS Energy, including the notes thereto, included in the Prospectus; and the audited and unaudited consolidated financial statements of Fortis, including the notes thereto, incorporated by reference in the Prospectus.

The underlying assumptions for the *pro forma* adjustments provide a reasonable basis for presenting the significant financial effect directly attributable to the Proposed Acquisition. These *pro forma* adjustments are tentative and are based on currently available financial information and certain estimates and assumptions. The actual adjustments to the consolidated financial statements will depend on a number of factors. Therefore, it is expected that the actual adjustments will differ from the *pro forma* adjustments, and the differences may be material.

2. DESCRIPTION OF TRANSACTION

Pursuant to an agreement and plan of a merger between Fortis, certain Fortis subsidiaries and UNS Energy, the Corporation will indirectly purchase all of the outstanding common shares of UNS Energy for US$60.25 per share. The net purchase price, including (i) payment for unexercised stock options and performance shares and restricted stock units; and (ii) estimated acquisition costs of $30 million, will be approximately $2.6 billion. The Corporation will also assume UNS Energy debt, which was approximately $1.9 billion as at September 30, 2013.

The accompanying unaudited *pro forma* consolidated financial statements assume that the Proposed Acquisition will be financed through the proceeds from a $1.8 billion common share issuance (as further described below) with the balance initially funded through debt.

The common equity is assumed to be issued through the 4% convertible unsecured subordinated debentures ("Convertible Debentures") represented by instalment receipts offered on a public offering and concurrent private placement basis, all as described in the Prospectus. The Corporation has also arranged a $2.0 billion committed bridge facility which together with the Convertible Debentures represented by instalment receipts contemplated in the Prospectus will fully fund the net purchase price and thereby ensure ample liquidity to close the Proposed Acquisition. The accompanying unaudited *pro forma* consolidated financial statements: (i) reflect the estimated costs of arranging the Convertible Debentures and bridge facility in acquisition costs (Note 3[e]); and (ii) assume that the Convertible Debentures will be issued and immediately fully converted into Fortis common shares at the assumed closing dates of the Proposed Acquisition. Therefore, the accompanying unaudited *pro forma* consolidated financial statements do not recognize interest costs associated with the Convertible Debentures. The Corporation anticipates that the closing period will be approximately 12 months but could span up to approximately 18 months, which would result in interest expense on the Convertible Debentures of up to approximately $108 million, or approximately $77 million net of income tax. Due to many factors, including the timing of regulatory approval, the estimated closing period is subject to change along with the estimated amount of interest expense on the Convertible Debentures and the related income tax recovery. Interest costs associated with the Convertible Debentures are expected to be funded through operating cash flows and/or the Corporation's existing credit facilities.

3. *PRO FORMA* ASSUMPTIONS AND ADJUSTMENTS

[a] Purchase Price and Financing Structure

The following is the estimated purchase price and assumed financing structure for the Proposed Acquisition. These estimates have been reflected in the accompanying unaudited *pro forma* consolidated financial statements.

Estimated Net Purchase Price

Unadjusted purchase price	$ 4,490
Estimated acquisition costs (Note 3[e])	30
Estimated net purchase price, before assumed debt	4,520
Assumed long-term debt of UNS Energy (Note 2)	(1,884)
Estimated net purchase price	$ 2,636

Estimated Net Funding Requirements

Estimated net purchase price	$2,636
Assumed long-term debt of UNS Energy (Note 2)	1,884
Common share issuance costs (Note 3[c])	72
Incremental long-term debt issuance costs (Note 3[d])	14
Estimated net funding requirements	$4,606

Assumed Financing Structure

Assumed long-term debt of UNS Energy	$1,884
Common share issuance (Note 3[c])	1,800
Incremental long-term debt (Note 3[d])	922
	$4,606

[b] Allocation of estimated net purchase price

The estimated net purchase price has been allocated to the estimated fair values of UNS Energy net assets and liabilities as at September 30, 2013 in accordance with the purchase method, as follows:

	UNS Energy	Fair Value and Other Adjustments	Net Total
Assets acquired:			
Cash and cash equivalents	$ 75	$—	$ 75
Accounts receivable	183	—	183
Prepaid expenses	28	—	28
Inventories	138	—	138
Regulatory assets	54	—	54
Deferred income taxes	69	—	69
Total current assets	547	—	547
Other assets	96	—	96
Regulatory assets	207	—	207
Utility capital assets	3,573	—	3,573
	$4,423	$—	$4,423
Liabilities assumed:			
Short-term borrowings	$ 24	—	$ 24
Accounts payable and other current liabilities	265	—	265
Regulatory liabilities	59	—	59
Current installments of capital lease and finance obligations	174	—	174
Total current liabilities	522	—	522
Other liabilities	244	—	244
Regulatory liabilities	307	—	307
Deferred income taxes	497	—	497
Long-term debt	1,552	—	1,552
Capital lease and finance obligations	134	—	134
	$3,256	$—	$3,256
Net assets at fair value, as at September 30, 2013			$1,167
Estimated net purchase price, before assumed debt and acquisition costs			2,606
Goodwill			$1,439

UNS Energy is a rate-regulated entity. The determination of revenues and earnings is based on regulated rates of return that are applied to historic values and does not change with a change of ownership. Therefore, no fair market value adjustments have been recognized as part of the purchase price on UNS Energy's assets and liabilities to be acquired because all of the economic benefits and obligations associated with them beyond regulated thresholds accrue to UNS Energy's customers. Consequently, the fair value of UNS Energy's assets and liabilities is assumed to be equal to their carrying amounts.

The excess of the estimated net purchase price of the Proposed Acquisition, before assumed debt and acquisition costs, over the assumed fair value of net assets acquired from UNS Energy is classified as goodwill on the accompanying unaudited *pro forma* consolidated balance sheet.

[c] Common share issuance

Assumed financing for the Proposed Acquisition contemplates the issuance, through the exercise of conversion rights under the Convertible Debentures, of approximately 58.6 million Fortis common shares at $30.72 per share for gross proceeds of approximately $1.8 billion. Underwriting and agency costs as well as private placement commitment fees are estimated at 4% of gross proceeds in the aggregate or approximately $72 million and will result in a corresponding deferred income tax asset of approximately $21 million based on the Corporation's statutory income tax rate of 29%.

[d] Incremental long-term debt

Assumed financing for the Proposed Acquisition contemplates the issuance of approximately $922 million of debt. Estimated debt issuance costs of approximately $14 million have been recognized as an other asset with a corresponding amortization expense of approximately $1 million recognized for the year ended December 31, 2012 and for the nine-months ended September 30, 2013 based on an estimated term of 10 years. The interest rate is estimated at 6%, which would result in incremental interest expense for the year ended December 31, 2012 and for the nine-months ended September 30, 2013 of $55 million and $41 million, respectively. Incremental interest expense would result in corresponding deferred income tax benefits of $16 million and $12 million, respectively, based on the Corporation's statutory income tax rate of 29%.

[e] Acquisition costs

Acquisition costs are estimated at approximately $30 million, or approximately $24 million net of income tax. The acquisition costs will create a deferred income tax asset of approximately $1 million and a reduction of $5 million to current income taxes payable. Acquisition costs are composed of estimated investment banking, accounting, tax, legal and other costs associated with the completion of the Proposed Acquisition. These costs have been included as a *pro forma* adjustment to retained earnings as opposed to being reflected in the unaudited *pro forma* consolidated statements of earnings of the Corporation on the basis that these expenses are directly incremental to the acquisition of UNS Energy and are non-recurring in nature.

[f] Income taxes

Income taxes applicable to the *pro forma* adjustments are calculated at Fortis' average tax rates of 29% (CDN rate) and 38% (US rate) for the year ended December 31, 2012 and for the nine-months ended September 30, 2013. To reflect an income tax benefit related to intercompany financing, a reduction in income tax expense of $11 million and $8 million has been recorded in the accompanying unaudited *pro forma* consolidated statement of earnings for the year ended December 31, 2012 and for the nine-months ended September 30, 2013, respectively.

The deferred income tax asset and liability is the cumulative amount of tax applicable to temporary differences between the accounting and tax values of assets and liabilities. Deferred income tax assets and liabilities are measured at the tax rates expected to apply when these differences reverse. For the purpose of the accompanying unaudited *pro forma* consolidated financial statements, deferred income tax rates of 29% (CDN rate) and 38% (US rate) have been used.

[g] UNS Energy historical shareholders' equity

The historical shareholders' equity of UNS Energy, which includes retained earnings, accumulated other comprehensive income and common shares, has been eliminated on consolidation.

[h] Earnings per common share

The calculation of the *pro forma* earnings per common share for the year ended December 31, 2012, and for the nine-months ended September 30, 2013 reflects the assumed issuance of approximately 58.6 million Fortis common shares as if the issuance had taken place as at January 1, 2012.

[i] Foreign exchange translation

The assets and liabilities of UNS Energy, which has a US dollar functional currency, are translated at the exchange rate in effect as at the unaudited *pro forma* consolidated balance sheet date. Revenue and expenses of UNS Energy's operations are translated at the average exchange rate in effect during the reporting period. The following exchange rates were utilized for the unaudited *pro-forma* consolidated financial statements:

Balance Sheet (US$ to C$)	
Spot rate — September 30, 2013	1.03
Income Statement (US$ to C$)	
Average rate — January 1, 2012 to December 31, 2012	1.00
Average rate — January 1, 2013 to September 30, 2013	1.02

CERTIFICATE OF FORTIS INC.

Dated: December 20, 2013

This short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of each of the provinces of Canada.

(Signed) H. STANLEY MARSHALL President and Chief Executive Officer	(Signed) BARRY V. PERRY Vice-President, Finance and Chief Financial Officer

On behalf of the Board of Directors

(Signed) DAVID G. NORRIS Director	(Signed) PETER E. CASE Director

CERTIFICATE OF THE UNDERWRITERS

Dated: December 20, 2013

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of each of the provinces of Canada.

SCOTIA CAPITAL INC.	RBC DOMINION SECURITIES INC.	TD SECURITIES INC.	CIBC WORLD MARKETS INC.
(Signed) Stuart Lochray	(Signed) David Dal Bello	(Signed) Harold Holloway	(Signed) David H. Williams

BMO NESBITT BURNS INC.

(Signed) Aaron Engen

NATIONAL BANK FINANCIAL INC

(Signed) Iain Watson

DESJARDINS SECURITIES INC.

(Signed) A. Thomas Little

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