Oct. 26, 2017

414 Nicollet Mall
Minneapolis, MN 55401

# XCEL ENERGY
# THIRD QUARTER 2017 EARNINGS REPORT

- GAAP and ongoing 2017 third quarter earnings per share were $0.97 compared with $0.90 per share in 2016.
- Xcel Energy narrows its 2017 GAAP and ongoing earnings guidance to $2.27 to $2.32 per share compared with the previous guidance issued of $2.25 to $2.35 per share.
- Xcel Energy initiates 2018 GAAP and ongoing earnings guidance of $2.37 to $2.47 per share.
- Xcel Energy revises long-term EPS growth rate objectives to 5 to 6 percent.

MINNEAPOLIS — Xcel Energy Inc. (NYSE: XEL) today reported 2017 third quarter GAAP and ongoing earnings of $492 million, or $0.97 per share, compared with $458 million, or $0.90 per share, in the same period in 2016.

Earnings for the third quarter of 2017 increased due to higher electric margins to recover infrastructure investments, along with a lower effective tax rate and lower operating and maintenance expenses, partially offset by higher depreciation expense and property taxes.

“Third quarter earnings were strong,” said Ben Fowke, chairman, president and CEO of Xcel Energy. “Results lined up with our expectations and we expect to deliver 2017 earnings within our narrowed guidance range. In addition, we are well positioned for the future and are issuing 2018 earnings guidance of $2.37 to $2.47 per share, which is consistent with our long-term earnings growth objective.”

“We have made progress in our Steel-for-Fuel investment strategy with our proposal for a new 300 megawatt wind farm in South Dakota. We also announced our proposed Colorado Energy Plan, which would increase our renewable portfolio to 55 percent of our energy mix in Colorado by 2026, while transitioning from coal generation. Our Steel-for-Fuel strategy and Colorado Energy Plan deliver tremendous value to our customers and build on Xcel Energy’s commitment to transition our energy fleet to cleaner, carbon free resources while keeping customer bills low,” concluded Fowke.

At 9:00 a.m. CDT today, Xcel Energy will host a conference call to review financial results. To participate in the call, please dial-in 5 to 10 minutes prior to the start and follow the operator’s instructions.

| | |
|---|---|
| US Dial-In: | (800) 289-0496 |
| International Dial-In: | (719) 325-4835 |
| Conference ID: | 7237091 |

The conference call also will be simultaneously broadcast and archived on Xcel Energy’s website at www.xcelenergy.com. To access the presentation, click on Investor Relations. If you are unable to participate in the live event, the call will be available for replay from 1:00 p.m. CDT on Oct. 26 through 11:00 p.m. CDT on Oct. 27.

Replay Numbers

| | |
|---|---|
| US Dial-In: | (888) 203-1112 |
| International Dial-In: | (719) 457-0820 |
| Access Code: | 7237091 |

Except for the historical statements contained in this release, the matters discussed herein, are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including our 2017 and 2018 earnings per share guidance and assumptions, are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed in Xcel Energy's Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2016 and subsequent securities filings, could cause actual results to differ materially from management expectations as suggested by such forward-looking information: general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) to obtain financing on favorable terms; business conditions in the energy industry; including the risk of a slow down in the U.S. economy or delay in growth, recovery, trade, fiscal, taxation and environmental policies in areas where Xcel Energy has a financial interest; customer business conditions; actions of credit rating agencies; competitive factors including the extent and timing of the entry of additional competition in the markets served by Xcel Energy; unusual weather; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; financial or regulatory accounting policies imposed by regulatory bodies; outcomes of regulatory proceedings; availability or cost of capital; and employee work force factors.

For more information, contact:


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*This information is not given in connection with any sale, offer for sale or offer to buy any security.*

# XCEL ENERGY INC. AND SUBSIDIARIES
## CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)
*(amounts in thousands, except per share data)*

| | Three Months Ended Sept. 30 | | Nine Months Ended Sept. 30 | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| **Operating revenues** | | | | |
| Electric | $ 2,783,569 | $ 2,799,964 | $ 7,420,646 | $ 7,209,225 |
| Natural gas | 214,253 | 221,956 | 1,129,795 | 1,046,544 |
| Other | 19,075 | 18,227 | 57,806 | 56,500 |
| Total operating revenues | 3,016,897 | 3,040,147 | 8,608,247 | 8,312,269 |
| | | | | |
| **Operating expenses** | | | | |
| Electric fuel and purchased power | 1,006,160 | 1,037,263 | 2,850,480 | 2,755,083 |
| Cost of natural gas sold and transported | 63,998 | 67,566 | 543,452 | 469,754 |
| Cost of sales — other | 8,451 | 8,648 | 25,216 | 25,225 |
| Operating and maintenance expenses | 541,539 | 590,009 | 1,706,102 | 1,764,397 |
| Conservation and demand side management expenses | 73,728 | 63,914 | 206,121 | 177,266 |
| Depreciation and amortization | 371,091 | 328,503 | 1,102,015 | 971,057 |
| Taxes (other than income taxes) | 133,571 | 117,190 | 410,591 | 400,982 |
| Total operating expenses | 2,198,538 | 2,213,093 | 6,843,977 | 6,563,764 |
| | | | | |
| **Operating income** | 818,359 | 827,054 | 1,764,270 | 1,748,505 |
| | | | | |
| Other income, net | 5,089 | 578 | 14,143 | 6,388 |
| Equity earnings of unconsolidated subsidiaries | 7,080 | 9,701 | 22,496 | 32,500 |
| Allowance for funds used during construction — equity | 23,483 | 17,199 | 54,182 | 45,042 |
| | | | | |
| **Interest charges and financing costs** | | | | |
| Interest charges — includes other financing costs of $5,923, $6,060, $17,657 and $19,026, respectively | 167,803 | 165,857 | 497,932 | 485,280 |
| Allowance for funds used during construction — debt | (10,724) | (7,532) | (25,359) | (20,206) |
| Total interest charges and financing costs | 157,079 | 158,325 | 472,573 | 465,074 |
| | | | | |
| **Income before income taxes** | 696,932 | 696,207 | 1,382,518 | 1,367,361 |
| Income taxes | 204,791 | 238,412 | 423,844 | 471,459 |
| **Net income** | $ 492,141 | $ 457,795 | $ 958,674 | $ 895,902 |
| | | | | |
| **Weighted average common shares outstanding:** | | | | |
| Basic | 508,581 | 508,941 | 508,468 | 508,840 |
| Diluted | 509,242 | 509,566 | 509,052 | 509,396 |
| | | | | |
| **Earnings per average common share:** | | | | |
| Basic | $ 0.97 | $ 0.90 | $ 1.89 | $ 1.76 |
| Diluted | 0.97 | 0.90 | 1.88 | 1.76 |
| | | | | |
| **Cash dividends declared per common share** | $ 0.36 | $ 0.34 | $ 1.08 | $ 1.02 |

Due to the seasonality of Xcel Energy's operating results, quarterly financial results are not an appropriate base from which to project annual results.

The only common equity securities that are publicly traded are common shares of Xcel Energy Inc. The diluted earnings and earnings per share (EPS) of each subsidiary discussed below do not represent a direct legal interest in the assets and liabilities allocated to such subsidiary but rather represent a direct interest in our assets and liabilities as a whole. Ongoing diluted EPS for Xcel Energy and by subsidiary is a financial measure not recognized under generally accepted accounting principles (GAAP). Ongoing diluted EPS is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary, adjusted for certain items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. We use this non-GAAP financial measure to evaluate and provide details of Xcel Energy's core earnings and underlying performance. We believe this measurement is useful to investors in facilitating period over period comparisons and evaluating or projecting financial results. This non-GAAP financial measure should not be considered as an alternative to measures calculated and reported in accordance with GAAP.

## Note 1. Earnings Per Share Summary

The following table summarizes diluted EPS for Xcel Energy:

| | Three Months Ended Sept. 30 | | Nine Months Ended Sept. 30 | |
|---|---|---|---|---|
| **Diluted Earnings (Loss) Per Share** | **2017** | **2016** | **2017** | **2016** |
| NSP-Minnesota | $ 0.45 | $ 0.41 | $ 0.81 | $ 0.74 |
| Public Service Company of Colorado (PSCo) | 0.37 | 0.34 | 0.78 | 0.74 |
| Southwestern Public Service Company (SPS) | 0.13 | 0.13 | 0.25 | 0.24 |
| NSP-Wisconsin | 0.04 | 0.05 | 0.12 | 0.11 |
| Equity earnings of unconsolidated subsidiaries | 0.01 | 0.01 | 0.03 | 0.04 |
| Regulated utility [(a)] | 1.00 | 0.94 | 1.98 | 1.87 |
| Xcel Energy Inc. and other | (0.03) | (0.04) | (0.10) | (0.11) |
| **GAAP diluted EPS** | **$ 0.97** | **$ 0.90** | **$ 1.88** | **$ 1.76** |

(a) Amounts may not add due to rounding.

***NSP-Minnesota*** — Earnings increased $0.04 per share for the third quarter of 2017 and $0.07 per share year-to-date. The year-to-date increase in earnings reflects electric rate increases, lower effective tax rate (ETR) and reduced operating and maintenance (O&M) expenses. The decrease in the ETR is largely driven by resolution of IRS appeals/audits and an increase in research and experimentation credits. The lower O&M expenses primarily relate to the timing of maintenance activities and the overhauls at various generation facilities and reduced expense for nuclear refueling outages. These positive factors were partially offset by depreciation expense (for additional capital investments, including the Courtenay Wind Farm, and prior year amortization of Minnesota's excess depreciation reserve) and higher property taxes.

***PSCo*** — Earnings increased $0.03 per share for the third quarter of 2017 and $0.04 per share year-to-date. The year-to-date increase in earnings, driven by higher electric margins, lower O&M expenses and lower ETR, were partially offset by increased depreciation expense associated with electric and natural gas investments. The lower O&M expenses are driven by the timing of maintenance and overhauls at various generation facilities and the impact of costs associated with storm damage in 2016.

***SPS*** — Earnings were flat for the third quarter of 2017 and increased $0.01 per share year-to-date. The year-to-date increase in electric margin was attributable to rate increases in Texas and New Mexico, partially offset by the impact of unfavorable weather. This increase was largely offset by higher depreciation expense for transmission and distribution investments and timing of O&M expenses, including the prior year deferrals associated with the Texas 2016 rate case.

***NSP-Wisconsin*** — Earnings decreased $0.01 per share for the third quarter of 2017 and increased $0.01 per share year-to-date. The year-to-date change was driven by increases in electric and natural gas rates, partially offset by depreciation expense primarily related to transmission and distribution investments and the impact of unfavorable weather.

The following table summarizes significant components contributing to the changes in 2017 EPS compared with the same period in 2016:

| Diluted Earnings (Loss) Per Share | Three Months Ended Sept. 30 | Nine Months Ended Sept. 30 |
|---|---|---|
| **2016 GAAP diluted EPS** | **$ 0.90** | **$ 1.76** |
| | | |
| Components of change — 2017 vs. 2016 | | |
| Higher electric margins | 0.02 | 0.14 |
| Lower ETR [(a)] | 0.07 | 0.10 |
| Lower O&M expenses | 0.06 | 0.07 |
| Higher natural gas margins | — | 0.01 |
| Higher depreciation and amortization | (0.05) | (0.16) |
| Higher conservation and DSM expenses (offset by higher revenues) | (0.01) | (0.03) |
| Other, net | (0.02) | (0.01) |
| **2017 GAAP diluted EPS** | **$ 0.97** | **$ 1.88** |

(a) Lower ETR includes the impact of an additional $9.6 million and $18.4 million of wind production tax credits (PTCs) for the three and nine months ended Sept. 30, 2017, respectively, which are largely flowed back to customers through electric margin.

## Note 2. Regulated Utility Results

***Estimated Impact of Temperature Changes on Regulated Earnings*** — Unusually hot summers or cold winters increase electric and natural gas sales, while mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances and the amount of natural gas or electricity historically used per degree of temperature. Weather deviations from normal levels can affect Xcel Energy's financial performance.

Degree-day or Temperature-Humidity Index (THI) data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature and humidity. Heating degree-days (HDD) is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. Cooling degree-days (CDD) is the measure of the variation in the weather based on the extent to which the average daily temperature rises above 65° Fahrenheit. Each degree of temperature above 65° Fahrenheit is counted as one CDD, and each degree of temperature below 65° Fahrenheit is counted as one HDD. In Xcel Energy's more humid service territories, a THI is used in place of CDD, which adds a humidity factor to CDD. HDD, CDD and THI are most likely to impact the usage of Xcel Energy's residential and commercial customers. Industrial customers are less sensitive to weather.

Normal weather conditions are defined as either the 20-year or 30-year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction, based on regulatory practice. To calculate the impact of weather on demand, a demand factor is applied to the weather impact on sales.

The percentage increase (decrease) in normal and actual HDD, CDD and THI is provided in the following table:

| | Three Months Ended Sept. 30 | | | Nine Months Ended Sept. 30 | | |
|---|---|---|---|---|---|---|
| | 2017 vs. Normal | 2016 vs. Normal | 2017 vs. 2016 | 2017 vs. Normal | 2016 vs. Normal | 2017 vs. 2016 |
| HDD | (16.5)% | (52.6)% | 67.5% | (13.6)% | (12.7)% | (2.2)% |
| CDD | 5.3 | 11.0 | (4.5) | 5.9 | 8.3 | (1.8) |
| THI | (11.6) | 6.5 | (17.5) | (10.6) | 8.6 | (18.5) |

***Weather*** — The following table summarizes the estimated impact of temperature variations on EPS compared with normal weather conditions:

| | Three Months Ended Sept. 30 | | | Nine Months Ended Sept. 30 | | |
|---|---|---|---|---|---|---|
| | 2017 vs. Normal | 2016 vs. Normal | 2017 vs. 2016 | 2017 vs. Normal | 2016 vs. Normal | 2017 vs. 2016 |
| Retail electric | $ (0.011) | $ 0.024 | $ (0.035) | $ (0.032) | $ 0.020 | $ (0.052) |
| Firm natural gas | — | (0.001) | 0.001 | (0.020) | (0.014) | (0.006) |
| Total (excluding decoupling) | $ (0.011) | $ 0.023 | $ (0.034) | $ (0.052) | $ 0.006 | $ (0.058) |
| Decoupling – Minnesota | 0.015 | (0.008) | 0.023 | 0.023 | (0.009) | 0.032 |
| Total (adjusted for recovery from decoupling) | $ 0.004 | $ 0.015 | $ (0.011) | $ (0.029) | $ (0.003) | $ (0.026) |

***Sales Growth (Decline)*** — The following tables summarize Xcel Energy and its subsidiaries' sales growth (decline) for actual and weather-normalized sales in 2017 compared to the same period in 2016:

| | Three Months Ended Sept. 30 | | | | |
|---|---|---|---|---|---|
| | NSP-Minnesota | PSCo | SPS | NSP-Wisconsin | Xcel Energy |
| **Actual** | | | | | |
| Electric residential [(a)] | (6.8)% | (2.5)% | (7.4)% | (6.9)% | (5.3)% |
| Electric commercial and industrial | (2.7) | 0.8 | (1.0) | 1.5 | (0.9) |
| Total retail electric sales | (3.9) | (0.3) | (2.5) | (0.8) | (2.2) |
| Firm natural gas sales | 8.5 | 4.7 | N/A | 11.4 | 6.2 |

| | Three Months Ended Sept. 30 | | | | |
|---|---|---|---|---|---|
| | NSP-Minnesota | PSCo | SPS | NSP-Wisconsin | Xcel Energy |
| **Weather-normalized** | | | | | |
| Electric residential [(a)] | (1.5)% | (3.0)% | (2.0)% | (0.4)% | (2.1)% |
| Electric commercial and industrial | (1.9) | 0.7 | 0.3 | 3.0 | (0.2) |
| Total retail electric sales | (1.8) | (0.6) | (0.3) | 2.0 | (0.8) |
| Firm natural gas sales | 6.9 | (0.6) | N/A | 9.6 | 2.1 |

| | Nine Months Ended Sept. 30 | | | | |
|---|---|---|---|---|---|
| | NSP-Minnesota | PSCo | SPS | NSP-Wisconsin | Xcel Energy |
| **Actual** | | | | | |
| Electric residential [(a)] | (3.3)% | (1.9)% | (4.4)% | (2.7)% | (2.9)% |
| Electric commercial and industrial | (1.6) | 0.6 | 0.7 | 1.5 | (0.2) |
| Total retail electric sales | (2.1) | (0.2) | (0.4) | 0.3 | (1.0) |
| Firm natural gas sales | 4.4 | (5.5) | N/A | 4.5 | (1.9) |

| | Nine Months Ended Sept. 30 | | | | |
|---|---|---|---|---|---|
| | NSP-Minnesota | PSCo | SPS | NSP-Wisconsin | Xcel Energy |
| **Weather-normalized** | | | | | |
| Electric residential [(a)] | (0.5)% | (1.5)% | (1.7)% | 0.4% | (1.0)% |
| Electric commercial and industrial | (1.0) | 0.7 | 1.0 | 2.1 | 0.2 |
| Total retail electric sales | (0.9) | — | 0.3 | 1.6 | (0.2) |
| Firm natural gas sales | 4.4 | (1.0) | N/A | 4.0 | 1.0 |

| | Nine Months Ended Sept. 30 (Excluding Leap Day) [b] | | | | |
|---|---|---|---|---|---|
| | NSP-Minnesota | PSCo | SPS | NSP-Wisconsin | Xcel Energy |
| **Weather-normalized - adjusted for leap day** | | | | | |
| Electric residential [a] | (0.2)% | (1.2)% | (1.3)% | 0.8% | (0.6)% |
| Electric commercial and industrial | (0.7) | 1.0 | 1.3 | 2.4 | 0.6 |
| Total retail electric sales | (0.5) | 0.3 | 0.7 | 1.9 | 0.2 |
| Firm natural gas sales | 5.3 | (0.3) | N/A | 4.8 | 1.8 |

(a) Extreme weather variations, windchill and cloud cover may not be reflected in weather-normalized and actual growth estimates.

(b) The estimated impact of the 2016 leap day is excluded to present a more comparable year-over-year presentation. The estimated impact of the additional day of sales in 2016 was approximately 30-40 basis points for retail electric and 70-80 basis points for firm natural gas for the nine months ended.

Weather-normalized Electric Sales Growth (Decline) — Year-To-Date Excluding Leap Day

- NSP-Minnesota's residential sales decrease was a result of lower use per customer, partially offset by customer growth. The decline in commercial and industrial (C&I) sales was largely due to reduced usage, which offset an increase in the number of customers. Declines in services offset increased sales to large customers in manufacturing and energy industries.
- PSCo's decline in residential sales reflects lower use per customer, partially offset by customer additions. C&I growth was mainly due to an increase in customers and higher use for large C&I customers that support the mining, oil and natural gas industries, which were partially reduced by lower use for the small C&I class.
- SPS' residential sales fell largely due to lower use per customer. The increase in C&I sales reflects customer additions and greater use per customer driven by the oil and natural gas industry in the Permian Basin.
- NSP-Wisconsin's residential sales increase was primarily attributable to higher use per customer and customer additions. C&I growth was largely due to higher use per customer and an increase in sales to customers in the sand mining industry and large customers in the energy and manufacturing industries.

Weather-normalized Natural Gas Sales Growth (Decline) — Year-To-Date Excluding Leap Day

- Across most service territories, higher natural gas sales reflect an increase in the number of customers, partially offset by a decline in customer use.

***Electric Margin*** — Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas, coal and uranium used in the generation of electricity. However, these price fluctuations have minimal impact on electric margin due to fuel recovery mechanisms that recover fuel expenses. The following table details the electric revenues and margin:

| | Three Months Ended Sept. 30 | | Nine Months Ended Sept. 30 | |
|---|---|---|---|---|
| **(Millions of Dollars)** | 2017 | 2016 | 2017 | 2016 |
| Electric revenues | $ 2,784 | $ 2,800 | $ 7,421 | $ 7,209 |
| Electric fuel and purchased power | (1,006) | (1,037) | (2,850) | (2,755) |
| Electric margin | $ 1,778 | $ 1,763 | $ 4,571 | $ 4,454 |

The following table summarizes the components of the changes in electric margin:

| (Millions of Dollars) | Three Months Ended Sept. 30 2017 vs. 2016 | Nine Months Ended Sept. 30 2017 vs. 2016 |
|---|---|---|
| Retail rate increases (Texas, Minnesota, New Mexico and Wisconsin) | $ 25 | $ 102 |
| Non-fuel riders | 19 | 39 |
| Higher conservation and DSM revenues (offset by higher expenses) | 10 | 24 |
| Decoupling (weather portion - Minnesota) | 17 | 24 |
| Estimated impact of weather | (26) | (39) |
| Wholesale transmission revenue, net of costs | (24) | (37) |
| Conservation incentive | (8) | (12) |
| Other, net | 2 | 16 |
| Total increase in electric margin | $ 15 | $ 117 |

***Natural Gas Margin*** — Total natural gas expense varies with changing sales and the cost of natural gas. However, fluctuations in the cost of natural gas has minimal impact on natural gas margin due to natural gas cost recovery mechanisms. The following table details natural gas revenues and margin:

| (Millions of Dollars) | Three Months Ended Sept. 30 2017 | Three Months Ended Sept. 30 2016 | Nine Months Ended Sept. 30 2017 | Nine Months Ended Sept. 30 2016 |
|---|---|---|---|---|
| Natural gas revenues | $ 214 | $ 222 | $ 1,130 | $ 1,047 |
| Cost of natural gas sold and transported | (64) | (68) | (543) | (470) |
| Natural gas margin | $ 150 | $ 154 | $ 587 | $ 577 |

The following table summarizes the components of the changes in natural gas margin:

| (Millions of Dollars) | Three Months Ended Sept. 30 2017 vs. 2016 | Nine Months Ended Sept. 30 2017 vs. 2016 |
|---|---|---|
| Infrastructure and integrity riders | $ (1) | $ 11 |
| Estimated impact of weather | 1 | (4) |
| Other, net | (4) | 3 |
| Total (decrease) increase in natural gas margin | $ (4) | $ 10 |

***O&M Expenses*** — O&M expenses decreased $48.5 million, or 8.2 percent, for the third quarter of 2017 and $58.3 million, or 3.3 percent, year-to-date. The significant changes are summarized in the table below:

| (Millions of Dollars) | Three Months Ended Sept. 30 2017 vs. 2016 | Nine Months Ended Sept. 30 2017 vs. 2016 |
|---|---|---|
| Plant generation costs | $ (4.5) | $ (33.9) |
| Nuclear plant operations and amortization | (11.0) | (17.3) |
| Electric distribution costs | (16.0) | (10.7) |
| Transmission costs | (3.1) | (9.9) |
| Employee benefits expense | (7.0) | 9.7 |
| Texas 2016 electric rate case cost deferral | — | 7.9 |
| Other, net | (6.9) | (4.1) |
| Total decrease in O&M expenses | $ (48.5) | $ (58.3) |

- Plant generation costs decreased primarily due to the timing of planned maintenance and overhauls at a number of generation facilities;
- Nuclear plant operations and amortization expenses are lower mostly due to savings initiatives and reduced refueling outage costs;
- Electric distribution costs declined as a result of storm damage expense incurred in 2016; and
- Transmission costs decreased mostly due to the timing of transmission line maintenance.

***Conservation and DSM Expenses*** — Conservation and demand side management (DSM) expenses increased $9.8 million, or 15.4 percent, for the third quarter of 2017 and $28.9 million, or 16.3 percent, year-to-date. The increase was due to higher recovery rates and additional customer participation in electric conservation programs, mostly in Minnesota. Conservation and DSM expenses are generally recovered in our major jurisdictions concurrently through riders and base rates. Timing of recovery may not correspond to the period in which costs were incurred.

***Depreciation and Amortization*** — Depreciation and amortization increased $42.6 million, or 13.0 percent, for the third quarter of 2017 and $131.0 million, or 13.5 percent, year-to-date. The increase was primarily due to capital investments, including the Courtenay Wind Farm, a new enterprise resource planning system and prior year amortization of the excess depreciation reserve in Minnesota.

***Taxes (Other than Income Taxes)*** — Taxes (other than income taxes) increased $16.4 million, or 14.0 percent for the third quarter of 2017 and $9.6 million, or 2.4 percent year-to-date. The increase was primarily due to higher property taxes in Minnesota.

***AFUDC, Equity and Debt*** — Allowance for funds used during construction (AFUDC) increased $9.5 million for the third quarter of 2017 and $14.3 million year-to-date. The increase was primarily due to higher construction work in progress, particularly the Rush Creek wind project.

***Interest Charges*** — Interest charges increased $1.9 million, or 1.2 percent, for the third quarter of 2017 and $12.7 million, or 2.6 percent, year-to-date. The increase was related to higher debt levels to fund capital investments, partially offset by refinancings at lower interest rates.

***Income Taxes*** — Income tax expense decreased $33.6 million for the third quarter and $47.6 million for the first nine months of 2017, compared to the same periods in 2016. The decrease was primarily due to net tax benefits related to an increase in wind PTCs, the resolution of past appeals/audits, and an increase in research and experimentation credits. The ETR was 29.4 percent for the third quarter of 2017 compared with 34.2 percent for the same period in 2016 and 30.7 percent for the first nine months of 2017, compared to 34.5 percent for the first nine months of 2016. The lower ETR in 2017 was primarily due to the adjustments referenced above.

## Note 3. Xcel Energy Capital Structure, Financing and Credit Ratings

Following is the capital structure of Xcel Energy:

| (Billions of Dollars) | Sept. 30, 2017 | Percentage of Total Capitalization | Dec. 31, 2016 | Percentage of Total Capitalization |
|---|---|---|---|---|
| Current portion of long-term debt | $ 0.3 | 1% | $ 0.3 | 1% |
| Short-term debt | 0.5 | 2 | 0.4 | 2 |
| Long-term debt | 14.6 | 54 | 14.2 | 55 |
| Total debt | 15.4 | 57 | 14.9 | 58 |
| Common equity | 11.4 | 43 | 11.0 | 42 |
| Total capitalization | $ 26.8 | 100% | $ 25.9 | 100% |

***Credit Facilities*** — As of Oct. 24, 2017, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

| (Millions of Dollars) | Credit Facility [(a)] | Drawn [(b)] | Available | Cash | Liquidity |
|---|---|---|---|---|---|
| Xcel Energy Inc. | $ 1,000 | $ 366 | $ 634 | $ 1 | $ 635 |
| PSCo | 700 | 4 | 696 | 18 | 714 |
| NSP-Minnesota | 500 | 22 | 478 | — | 478 |
| SPS | 400 | 3 | 397 | 49 | 446 |
| NSP-Wisconsin | 150 | 119 | 31 | 1 | 32 |
| Total | $ 2,750 | $ 514 | $ 2,236 | $ 69 | $ 2,305 |

(a) These credit facilities expire in June 2021.
(b) Includes outstanding commercial paper and letters of credit.

***Credit Ratings*** — Access to the capital market at reasonable terms is partially dependent on credit ratings. The following ratings reflect the views of Moody's Investors Service (Moody's), Standard & Poor's Rating Services (Standard & Poor's), and Fitch Ratings (Fitch).

The highest credit rating for debt is Aaa/AAA and the lowest investment grade rating is Baa3/BBB-. The highest rating for commercial paper is P-1/A-1/F-1 and the lowest rating is P-3/A-3/F-3. A security rating is not a recommendation to buy, sell or hold securities. Ratings are subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

As of Oct. 24, 2017, the following represents the credit ratings assigned to Xcel Energy Inc. and its utility subsidiaries:

| Credit Type | Company | Moody's | Standard & Poor's | Fitch |
|---|---|---|---|---|
| Senior Unsecured Debt | Xcel Energy Inc. | A3 | BBB+ | BBB+ |
| | NSP-Minnesota | A2 | A- | A |
| | NSP-Wisconsin | A2 | A- | A |
| | PSCo | A3 | A- | A |
| | SPS | Baa1 | A- | BBB+ |
| Senior Secured Debt | NSP-Minnesota | Aa3 | A | A+ |
| | NSP-Wisconsin | Aa3 | A | A+ |
| | PSCo | A1 | A | A+ |
| | SPS | A2 | A | A- |
| Commercial Paper | Xcel Energy Inc. | P-2 | A-2 | F2 |
| | NSP-Minnesota | P-1 | A-2 | F2 |
| | NSP-Wisconsin | P-1 | A-2 | F2 |
| | PSCo | P-2 | A-2 | F2 |
| | SPS | P-2 | A-2 | F2 |

***Capital Expenditures*** — The estimated base capital expenditures for Xcel Energy for 2018 through 2022 are shown in the table below:

| | Base Capital Forecast | | | | | |
|---|---|---|---|---|---|---|
| By Subsidiary (Millions of Dollars) | 2018 | 2019 | 2020 | 2021 | 2022 | 2018 - 2022 Total |
| NSP-Minnesota | $ 1,370 | $ 1,910 | $ 1,450 | $ 1,590 | $ 1,500 | $ 7,820 |
| PSCo | 1,650 | 1,020 | 950 | 1,150 | 1,410 | 6,180 |
| SPS | 1,020 | 1,140 | 710 | 470 | 540 | 3,880 |
| NSP-Wisconsin | 250 | 250 | 240 | 280 | 290 | 1,310 |
| Other [(a)] | 20 | (90) | (90) | (30) | — | (190) |
| Total capital expenditures | $ 4,310 | $ 4,230 | $ 3,260 | $ 3,460 | $ 3,740 | $ 19,000 |

| By Function (Millions of Dollars) | Base Capital Forecast 2018 | 2019 | 2020 | 2021 | 2022 | 2018 - 2022 Total |
|---|---|---|---|---|---|---|
| Electric distribution | $ 750 | $ 810 | $ 870 | $ 1,110 | $ 1,380 | $ 4,920 |
| Renewables | 1,410 | 1,860 | 880 | 270 | — | 4,420 |
| Electric transmission | 770 | 540 | 570 | 860 | 980 | 3,720 |
| Electric generation | 520 | 370 | 290 | 520 | 530 | 2,230 |
| Natural gas | 460 | 400 | 410 | 420 | 510 | 2,200 |
| Other [(b)] | 400 | 250 | 240 | 280 | 340 | 1,510 |
| Total capital expenditures | $ 4,310 | $ 4,230 | $ 3,260 | $ 3,460 | $ 3,740 | $ 19,000 |

[(a)] Other category includes intercompany transfers for safe harbor wind turbines.
[(b)] Amounts in other category are net of intercompany transfers.

The base capital expenditure forecast does not include the Colorado Energy Plan, which if approved could increase the total capital investment up to $1.5 billion.

Xcel Energy’s capital expenditure forecast is subject to continuing review and modification. Actual capital expenditures may vary from estimates due to changes in electric and natural gas projected load growth, regulatory decisions, legislative initiatives, reserve requirements, availability of purchased power, alternative plans for meeting long-term energy needs, environmental regulation, and merger, acquisition and divestiture opportunities.

***Financing for Capital Expenditures through 2022*** — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes. The current estimated financing plans of Xcel Energy for 2018 through 2022 are shown in the table below.

| (Millions of Dollars) | |
|---|---|
| **Funding Capital Expenditures** | |
| Cash from Operations* | $ 13,920 |
| New Debt** | 4,695 |
| Equity through the Dividend Reinvestment Program (DRIP) and Benefit Programs | 385 |
| Base Capital Expenditures 2018-2022 | $ 19,000 |
| | |
| **Maturing Debt** | $ 3,450 |

* Net of dividends and pension funding.
** Reflects a combination of short and long-term debt; net of refinancing.

***Financing Activity*** — During 2017, Xcel Energy Inc. and its utility subsidiaries issued and anticipate issuing the following:

- PSCo issued $400 million of 3.80 percent first mortgage bonds due June 15, 2047;
- SPS issued $450 million of 3.70 percent first mortgage bonds due Aug. 15, 2047;
- NSP-Minnesota issued $600 million of 3.60 percent first mortgage bonds due Sept. 15, 2047;
- NSP-Wisconsin plans to issue approximately $100 million of first mortgage bonds in the fourth quarter; and
- Xcel Energy Inc. plans to issue short-term debt in the fourth quarter to meet financing needs.

Xcel Energy Inc. and its utility subsidiaries’ 2018 financing plans reflect the following:

- Xcel Energy Inc. plans to issue approximately $750 million of senior unsecured bonds;
- NSP-Minnesota plans to issue approximately $300 million of first mortgage bonds;
- NSP-Wisconsin plans to issue approximately $150 million of first mortgage bonds;
- PSCo plans to issue approximately $700 million of first mortgage bonds; and
- SPS plans to issue approximately $300 million of first mortgage bonds.

Financing plans are subject to change, depending on capital expenditures, internal cash generation, market conditions and other factors. Xcel Energy does not anticipate issuing any additional equity, beyond its DRIP and benefit programs, over the next five years based on its current base capital expenditure plan.

***Debt Redemption***

- On Aug. 30, 2017, SPS reacquired $250 million of debt with a coupon rate of 8.75 percent and an original maturity date of Dec. 1, 2018. The redemption resulted in payment of an early redemption premium of $21.6 million which was deferred as a regulatory asset.
- On Sept. 29, 2017, NSP-Minnesota reacquired $500 million of debt with a coupon rate of 5.25 percent and an original maturity date of March 1, 2018. The redemption resulted in payment of an early redemption premium of $7.9 million which was deferred as a regulatory asset.

## Note 4. Rates and Regulation

***NSP-Wisconsin – Wisconsin 2018 Electric and Natural Gas Rate Case*** — In May 2017, NSP-Wisconsin filed a request with the Public Service Commission of Wisconsin (PSCW) to increase electric rates by $24.7 million, or 3.6 percent, and natural gas rates by $12.0 million, or 10.1 percent, effective Jan. 1, 2018. The rate filing is based on a 2018 forecast test year, a return on equity (ROE) of 10.0 percent, an equity ratio of 52.53 percent and a forecasted rate base of approximately $1.2 billion for the electric utility and $138.4 million for the natural gas utility.

In September 2017, the PSCW Staff and the intervenors filed testimony. The PSCW Staff recommended an electric rate increase of $10.9 million, or 1.6 percent, and a natural gas rate increase of $9.9 million, or 8.3 percent, based on a ROE of 9.8 percent and an equity ratio of 51.45 percent.

A PSCW decision is anticipated in December 2017 with new rates effective in January 2018.

***PSCo – Colorado 2017 Multi-Year Electric Rate Case*** — In October 2017, PSCo filed a multi-year request with the Colorado Public Utilities Commission (CPUC) seeking to increase electric rates approximately $245 million over four years. The request, summarized below, is based on forecast test years (FTY) ending Dec. 31, a 10.0 percent ROE and an equity ratio of 55.25 percent.

| Revenue Request (Millions of Dollars) | 2018 | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|
| Revenue request | $ 74.6 | $ 74.9 | $ 59.7 | $ 35.7 | $ 244.9 |
| Clean Air Clean Jobs Act (CACJA) revenue conversion to base rates [(a)] | 90.4 | — | — | — | 90.4 |
| Transmission Cost Adjustment (TCA) revenue conversion to base rates [(a)] | 42.7 | — | — | — | 42.7 |
| Total [(b)] | $ 207.7 | $ 74.9 | $ 59.7 | $ 35.7 | $ 378.0 |
| | | | | | |
| Expected year-end rate base (billions of dollars) [(b)] | $ 6.8 | $ 7.1 | $ 7.3 | $ 7.4 | |

(a) The roll-in of each of the TCA and CACJA rider revenues into base rates will not have an impact on total customer bills or total revenue as these costs are already being recovered through a rider. Transmission investments for 2019 through 2021 will be recovered through the TCA rider.

(b) This base rate request does not include the impacts associated with the renewable energy standard adjustment and retail electric commodity adjustment for the Rush Creek wind investments or any impacts of the proposed Colorado Energy Plan.

Final rates are expected to be effective in June 2018. PSCo also proposed a stay-out provision and earnings test through 2021.

***PSCo – Colorado 2017 Multi-Year Natural Gas Rate Case*** — In June 2017, PSCo filed a multi-year request with the CPUC seeking to increase retail natural gas rates approximately $139 million over three years. The request, detailed below, is based on FTYs, a 10.0 percent ROE and an equity ratio of 55.25 percent.

| **Revenue Request (Millions of Dollars)** | **2018** | **2019** | **2020** | **Total** |
|---|---|---|---|---|
| Revenue request | $ 63.2 | $ 32.9 | $ 42.9 | $ 139.0 |
| Pipeline System Integrity Adjustment (PSIA) revenue conversion to base rates [(a)] | — | 93.9 | — | 93.9 |
| Total | $ 63.2 | $ 126.8 | $ 42.9 | $ 232.9 |
| | | | | |
| Expected year-end rate base (billions of dollars) [(b)] | $ 1.5 | $ 2.3 | $ 2.4 | |

(a) The roll-in of PSIA rider revenue into base rates will not have an impact on customer bills or total revenue as these costs are already being recovered through the rider. PSCo plans to request new PSIA rates for 2018 in November 2017. The recovery of incremental PSIA related investments in 2019 and 2020 are included in the base rate request.

(b) The additional rate base in 2019 predominantly reflects the roll-in of capital associated with the PSIA rider.

In October 2017, several parties filed answer testimony. The CPUC Staff (Staff) and the Office of Consumer Counsel (OCC), recommended a single 2016 historic test year (HTY), based on an average 13-month rate base, and opposed a multi-year plan (MYP). The Staff and OCC recommended an equity capital structure of 48.73 percent and 51.2 percent, respectively. Both the Staff and the OCC recommended the existing PSIA rider expire with the 2018 rates rolled into base rates beginning Jan. 1, 2019. Planned investments in 2019 and 2020 would be recoverable through base rates, subject to a future rate case.

The following represents adjustments to PSCo's filed request made by Staff and OCC for 2018:

| **(Millions of Dollars)** | **Staff** | **OCC** |
|---|---|---|
| Filed 2018 new revenue request | $ 63.2 | $ 63.2 |
| Impact of the change in test year | 4.4 | 4.4 |
| PSCo's filed 2016 HTY | $ 67.6 | $ 67.6 |
| | | |
| Recommended adjustments: | | |
| ROE (9.0 percent) | (13.5) | (13.5) |
| Capital structure and cost of debt | (10.2) | (7.5) |
| Change in amortization period | (5.4) | — |
| Prepaid pension and retiree medical assets | (5.2) | — |
| Change from 2016 year end to average rate base | (4.8) | (4.8) |
| Other, net | (5.0) | (5.5) |
| Total adjustments | $ (44.1) | $ (31.3) |
| | | |
| Total recommended rate increase | $ 23.5 | $ 36.3 |

The next steps in the procedural schedule are as follows:

- Rebuttal testimony — Nov. 3, 2017;
- Intervenor sur-rebuttal testimony — Nov. 15, 2017;
- Hearings — Dec. 11 - 15 and 18 - 19, 2017; and
- Statements of position — Jan. 19, 2018.

Interim rates, subject to refund, are expected to be effective Jan. 1, 2018. A final decision by the CPUC is anticipated in March 2018.

***SPS – Texas 2017 Electric Rate Case*** — In August 2017, SPS filed a $66.4 million, or 7.1 percent, retail electric, non-fuel base rate increase case in Texas with each of its Texas municipalities and the Public Utilities Commission of Texas (PUCT). The request was based on the 12-month period ended June 30, 2017, with the final three months based on estimates, a requested ROE of 10.25 percent, a Texas retail electric rate base of approximately $1.9 billion and an equity ratio of 53.97 percent.

In October 2017, SPS revised its request to $54.6 million, or 5.8 percent, which reflects updated actual results. In addition, approximately $4.4 million of rate case expenses was bifurcated into a separate docket.

The following table summarizes SPS' revised rate increase request:

| Revenue Request (Millions of Dollars) | | |
|---|---|---|
| Incremental revenue request | $ | 69.2 |
| Transmission Cost Recovery Factor (TCRF) revenue conversion to base rates [(a)] | | (14.6) |
| Net revenue increase request | $ | 54.6 |

(a) The roll-in of the TCRF rider revenue into base rates will not have an impact on customer bills or total revenue as these costs are already being recovered through the rider. SPS can request another TCRF rider after the conclusion of this rate case to recover transmission investments subsequent to June 30, 2017.

Key dates in the procedural schedule are as follows:

- Intervenors' direct testimony — Feb. 22, 2018;
- PUCT Staff direct testimony — March 1, 2018;
- PUCT Staff and intervenors' cross-rebuttal testimony — March 22, 2018;
- SPS' rebuttal testimony — March 23, 2018;
- Hearings — April 10 - 20, 2018; and
- Statutory deadline — Aug. 31, 2018.

The final rates are expected to be effective retroactive to Jan. 23, 2018 through a customer surcharge. A PUCT decision is expected in the third quarter of 2018.

***PSCo – Colorado Energy Plan (CEP)*** — In May 2016, PSCo filed its 2016 Electric Resource Plan which included the estimated need for additional generation resources through 2024. In April 2017, the CPUC approved the modeling assumptions that will be used in the Request for Proposal (RFP) process. In August 2017, PSCo filed an updated capacity need with the CPUC of 450 megawatts (MW).

In August 2017, PSCo, along with various other stakeholders, filed a stipulation agreement proposing the CEP. The major components include:

- Early retirement of 660 MW of coal-fired generation at Comanche Units 1 (2022) and 2 (2025);
- An RFP which could result in the addition of up to 1,000 MW of wind, 700 MW solar and 700 MW of natural gas and/or storage;
- Utility ownership targets of 50 percent renewable generation resources and 75 percent of natural gas-fired, storage, or renewable with storage generation resources;
- Accelerated depreciation for the early retirement of the two Comanche units and establishment of a regulatory asset to collect the incremental depreciation expense and related costs;
- Reduction of the Renewable Energy Standard Adjustment rider, from two percent to one percent, subject to regulatory proceedings, effective beginning 2021 or 2022; and
- Construction of a new transmission switching station to further the development of renewable generating resources.

In August 2017, PSCo issued an All-Source RFP. Bids are due on Nov. 28, 2017. PSCo anticipates filing its' recommended portfolios in April 2018. The CPUC is expected to rule on the stipulation agreement in March 2018. A CPUC decision on the recommended portfolio is anticipated in the summer of 2018.

Approval of the CEP could increase the total capital investment up to $1.5 billion. The CEP is not included in PSCo and Xcel Energy's base capital expenditures forecast. See Note 3 for further discussion of the capital forecast.

***Xcel Energy – Wind Development*** — Xcel Energy plans to significantly expand its wind capacity at NSP-Minnesota, PSCo and SPS. The CPUC approved the Rush Creek wind project in 2016. In July 2017, the Minnesota Public Utilities Commission (MPUC) approved NSP-Minnesota's proposal to add 1,550 MW of new wind generation, including ownership of 1,150 MW of wind generation by NSP-Minnesota.

The PUCT and New Mexico Public Regulation Commission (NMPRC) are expected to rule on SPS' wind projects by the end of the first quarter of 2018. Hearings in Texas with the PUCT are scheduled for Nov. 6 through Nov. 17, 2017. Hearings in New Mexico with the NMPRC are scheduled for Nov. 28 through Dec. 1, 2017.

In September 2017, NSP-Minnesota filed with the MPUC seeking approval to build and own the Dakota Range project, a 300 MW wind project in South Dakota. The project is projected to be placed into service by the end of 2021 to qualify for 80 percent of the PTC. NSP-Minnesota has requested that the MPUC approve the proposed wind project by March 2018.

These wind projects (with the exception of the Dakota Range project) would qualify for 100 percent of the PTC and are expected to provide billions of dollars of savings to Xcel Energy's customers and substantial environmental benefits. Projected savings/benefits assume fuel costs and generation mix consistent with various commission approved resource plans.

The following table details these wind projects:

| Project Name | Capacity (MW) | State | Estimated Year of Completion | Ownership/PPA | Regulatory Status |
|---|---|---|---|---|---|
| Rush Creek | 600 | CO | 2018 | PSCo | Approved by CPUC |
| Freeborn | 200 | MN/IA | 2020 | NSP-Minnesota | Approved by MPUC |
| Blazing Star 1 | 200 | MN | 2019 | NSP-Minnesota | Approved by MPUC |
| Blazing Star 2 | 200 | MN | 2020 | NSP-Minnesota | Approved by MPUC |
| Lake Benton | 100 | MN | 2019 | NSP-Minnesota | Approved by MPUC |
| Foxtail | 150 | ND | 2019 | NSP-Minnesota | Approved by MPUC |
| Crowned Ridge | 300 | SD | 2019 | NSP-Minnesota | Approved by MPUC |
| Dakota Range | 300 | SD | 2021 | NSP-Minnesota | Pending MPUC Approval |
| Hale | 478 | TX | 2019 | SPS | Pending PUCT & NMPRC Approval |
| Sagamore | 522 | NM | 2020 | SPS | Pending PUCT & NMPRC Approval |
| Total Ownership | 3,050 | | | | |
| | | | | | |
| Crowned Ridge | 300 | SD | 2019 | PPA | Approved by MPUC |
| Clean Energy 1 | 100 | ND | 2019 | PPA | Approved by MPUC |
| Bonita | 230 | TX | 2019 | PPA | Pending PUCT & NMPRC Approval |
| Total PPA | 630 | | | | |
| Total Wind Capacity | 3,680 | | | | |

## Note 5. Xcel Energy Earnings Guidance and Long-Term EPS and Dividend Growth Rate Objectives

***Xcel Energy 2017 Earnings Guidance*** — Xcel Energy's narrowed 2017 GAAP and ongoing earnings guidance is $2.27 to $2.32 per share, compared with the previous issued guidance of $2.25 to $2.35 per share.[a] Key assumptions:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the remainder of the year.
- Weather-normalized retail electric sales are projected to be within a range of 0 percent to 0.5 percent over 2016 levels.
- Weather-normalized retail firm natural gas sales are projected to be within a range of 0 percent to 0.5 percent over 2016 levels.
- Capital rider revenue is projected to increase by $45 million to $55 million over 2016 levels.
- O&M expenses are projected to be flat.
- Depreciation expense is projected to increase approximately $180 million to $190 million over 2016 levels.
- Property taxes are projected to be within a range of approximately $0 million to $10 million over 2016 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $10 million to $20 million over 2016 levels.
- AFUDC — equity is projected to increase approximately $10 million to $20 million from 2016 levels.
- The ETR is projected to be approximately 31 percent.
- Average common stock and equivalents are projected to be approximately 509 million shares.

***Xcel Energy 2018 Earnings Guidance*** — Xcel Energy's 2018 GAAP and ongoing earnings guidance is $2.37 to $2.47 per share.[a] Key assumptions:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns.
- Weather-normalized retail electric sales are projected to be within a range of 0 percent to 0.5 percent over 2017 levels.
- Weather-normalized retail firm natural gas sales are projected to be within a range of 0 percent to 0.5 percent below 2017 levels.
- Capital rider revenue is projected to increase by $40 million to $50 million over 2017 levels.
- O&M expenses are projected to be flat.
- Depreciation expense is projected to increase approximately $120 million to$130 million over 2017 levels.
- Property taxes are projected to increase approximately $35 million to $45 million over 2017 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $20 million to $30 million over 2017 levels.
- AFUDC — equity is projected to increase approximately $20 million to $30 million from 2017 levels.
- The ETR is projected to be approximately 30 percent to 32 percent.
- Average common stock and equivalents are projected to be approximately 510 million shares.

[a] Ongoing earnings could differ from those prepared in accordance with GAAP for unplanned and/or unknown adjustments. Xcel Energy is unable to forecast if any of these items will occur or provide a quantitative reconciliation of the guidance for ongoing diluted EPS to corresponding GAAP diluted EPS.

***Long-Term EPS and Dividend Growth Rate Objectives*** — Xcel Energy expects to deliver an attractive total return to our shareholders through a combination of earnings growth and dividend yield, based on the following long-term objectives:

- Deliver long-term annual EPS growth of 5 percent to 6 percent off of a 2017 base of $2.30 per share (which represents the midpoint of the 2017 guidance range of $2.25 to$2.35 per share);
- Deliver annual dividend increases of 5 percent to 7 percent;
- Target a dividend payout ratio of 60 percent to 70 percent; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

Ongoing earnings is calculated using net income and adjusting for certain nonrecurring or infrequent items that are, in management's view, not reflective of ongoing operations.

**XCEL ENERGY INC. AND SUBSIDIARIES**
**EARNINGS RELEASE SUMMARY (UNAUDITED)**
*(amounts in thousands, except per share data)*

| | Three Months Ended Sept. 30 | |
|---|---|---|
| | 2017 | 2016 |
| **Operating revenues:** | | |
| Electric and natural gas | $ 2,997,822 | $ 3,021,920 |
| Other | 19,075 | 18,227 |
| Total operating revenues | 3,016,897 | 3,040,147 |
| | | |
| **Net income** | $ 492,141 | $ 457,795 |
| | | |
| Weighted average diluted common shares outstanding | 509,242 | 509,566 |
| | | |
| Components of EPS — Diluted | | |
| Regulated utility | $ 1.00 | $ 0.94 |
| Xcel Energy Inc. and other costs | (0.03) | (0.04) |
| **GAAP diluted EPS** | **$ 0.97** | **$ 0.90** |

| | Nine Months Ended Sept. 30 | |
|---|---|---|
| | 2017 | 2016 |
| **Operating revenues:** | | |
| Electric and natural gas | $ 8,550,441 | $ 8,255,769 |
| Other | 57,806 | 56,500 |
| Total operating revenues | 8,608,247 | 8,312,269 |
| | | |
| **Net income** | $ 958,674 | $ 895,902 |
| | | |
| Weighted average diluted common shares outstanding | 509,052 | 509,396 |
| | | |
| Components of EPS — Diluted | | |
| Regulated utility | $ 1.98 | $ 1.87 |
| Xcel Energy Inc. and other costs | (0.10) | (0.11) |
| **GAAP diluted EPS** | **$ 1.88** | **$ 1.76** |
| Book value per share | $ 22.53 | $ 21.63 |