BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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RE: IN THE MATTER OF ADVICE LETTER NO. 1672-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 7-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE JULY 18, 2014.	**)))))))))**	**PROCEEDING NO. 14AL-_______E**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF MARY P. SCHELL</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

June 17, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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SUMMARY OF DIRECT TESTIMONY OF MARY SCHELL

Ms. Mary P. Schell is Director, Corporate Financial Policy of Xcel Energy Services Inc. ("XES"). In this position, Ms. Schell is responsible for implementing the financing required to achieve target capital structure objectives at Public Service Company of Colorado ("Public Service" or "Company") and the other utility subsidiaries of Xcel Energy Inc. ("Xcel Energy"), and at Xcel Energy itself. She is also responsible for developing the necessary regulatory applications and testimony to gain regulatory approval for financing and to support financial integrity.

In her testimony, Ms. Schell provides current assessment of Public Service's financial integrity and explains that maintaining a strong credit quality enables the Company to access the capital markets on favorable terms in all market conditions. As part of this portion of her testimony, Ms. Schell discusses rating agency evaluation criteria. As Ms. Schell states, the Company presently has a credit rating of A-. She also shows how Public Service's stable financial health has benefitted customers through lower overall cost of debt and financing flexibility.

Ms. Schell then addresses the regulated capital structure of the Company, and supports maintaining the regulated equity ratio of 56 percent that has been in effect at Public Service since 2012. As she explains, a 56 percent regulated equity ratio will promote the continuing financial strength of Public Service. Ms. Schell discusses the relationship between the Company's regulated capital structure and its economic capital structure, which takes into account all debt and imputed debt associated with debt-like obligations, including operating leases and power purchase agreements. Ms. Schell testifies that a regulated capital structure of 56 percent equity will provide it with an economic equity ratio of 50.3 percent for 2015. As part of her discussion of the capital structure issue, Ms. Schell recommends that the "capital employed approach" be used to calculate the long-term debt balance included in the capital structure.

Ms. Schell supports the 4.68 percent cost of long-term debt reflected in the January 1, 2015 through December 31, 2015 Test Year ("Test Year"), explaining that the Company's strong financial health has been an important driver of the 95 basis point reduction in debt cost since the last electric rate case. Ms. Schell recommends that the capital employed approach also be used to determine the cost of long-term debt.

Finally, Ms. Schell presents the Company's overall cost of capital of 7.86 percent based on a 56 percent equity ratio, 4.68 percent cost of long term debt and the 10.35 percent return on equity recommended by Company witness Mr. Robert Hevert. She shows that the resulting credit metrics correspond to and support maintaining the Company's current A- corporate credit rating.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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DIRECT TESTIMONY AND ATTACHMENTS OF MARY P. SCHELL

INDEX

SECTION **PAGE**

LIST OF ATTACHMENTS

Attachment No. MPS-1	Standard & Poor's *Key Credit Factors for the Regulated Utilities Industry*
Attachment No. MPS-2	Standard & Poor's *Criteria Methodology: Business Risk/Financial Risk Matrix Expanded*
Attachment No. MPS-3	Moody's Investor Service: *Moody's upgrades Xcel Energy and its subsidiaries*
Attachment No. MPS-4	Fitch Ratings: *Fitch Upgrades PUBLIC SERVICE's IDR to A-*
Attachment No. MPS-5	Capital Structure and Costs for years 2013 and 2015
Attachment No. MPS-6	Capital Structure Example
Attachment No. MPS-7	Embedded Cost of Long-Term Debt for 2013 and Test Year 2015
Attachment No. MPS-8	Cost of Long-Term Debt Example
Attachment No. MPS-9	Public Service Credit Metrics based on S&P's Methodology for Imputed Debt

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	**Meaning**
Commission	Colorado Public Utilities Commission
CWIP	Construction Work In Progress
DSMCA	Demand Side Cost Management Cost Adjustment
EBITDA	Earnings Before Interest, Taxes, & Depreciation
HTY	Historic Test Year
PCCA	Purchase Capacity Cost Adjustment
PPA	Power Purchase Agreements
PSIA	Pipeline System Integrity Adjustment
Public Service, or Company	Public Service Company of Colorado
ROE	Return on Equity
S&P	Standard & Poor's
TCA	Transmission Cost Adjustment
Test Year	January 1, 2015 through December 31, 2015
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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DIRECT TESTIMONY AND ATTACHMENTS OF MARY P. SCHELL

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, AND RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mary P. Schell. My business address is Xcel Energy Inc., 414 Nicollet Mall, Suite 400, Minneapolis, MN 55401.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Xcel Energy Services, Inc. ("XES") as Director, Corporate Financial Policy. XES is a wholly owned subsidiary of Xcel Energy Inc. ("Xcel Energy"), and provides an array of support services to Public Service Company of Colorado ("Public Service" or "Company") and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE DESCRIBE YOUR DUTIES, RESPONSIBILITIES, AND QUALIFICATIONS?

A. As Director of Corporate Financial Policy, I am responsible for implementing the financing required to meet capital requirements and achieve target capital structure objectives at each of the regulated utility operating companies of Xcel Energy, including Public Service, and at Xcel Energy. I am also responsible for developing the necessary regulatory applications and testimony to gain regulatory approval for financings and to support financial integrity. A description of my qualifications, duties, and responsibilities is included as Attachment A.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to:

- Provide a current assessment of Public Service's financial integrity, discuss the credit rating agencies evaluation criteria, and explain how Public Service's stable overall financial health has benefitted our customers, resulting in lower cost of debt and financing flexibility;
- Present our recommended January 1, 2015 through December 31, 2015 Test Year ("Test Year") capital structure – i.e., a regulated equity ratio of 56 percent - as compared to our actual regulated capital structure as of December 31, 2013, and discuss the challenges we face at Public Service in managing our capital structure in light of the imputed debt effects of the Company's purchase power contracts and operating leases;

- Present our cost of long-term debt as of December 31, 2013 and our forecast cost of long-term debt for the Test Year taking into consideration our long-term debt financing plans during 2014 and 2015;
- Explain our proposal to change the method of calculating our long-term debt balance and cost of long-term debt from the par value method to a capital employed approach so that our capital structure more accurately reflects the proportion of debt and equity that we are using to fund our capital investments and the true cost of debt financing during the Test Year; and
- Present the recommended 7.86 percent cost of capital that should be used for setting rates for electric utility operations at Public Service based on an equity ratio of 56 percent, a 4.68 percent cost of long term debt, and a 10.35 percent recommended cost of equity as supported by Mr. Robert B. Hevert. I will also show how the resulting credit metrics for 2015 align with the guidelines provided by Standard & Poor's ("S&P") for an A- corporate credit rating.

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes, I am sponsoring Attachment No. MPS-1 through Attachment No. MPS-9.

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR TESTIMONY?

A. I am recommending that the Colorado Public Utilities Commission ("Commission") adopt our proposed capital structure and cost of long-term debt for use in the Test Year cost of service presented by Ms. Deborah Blair.

II. <u>FINANCIAL INTEGRITY</u>

Q. WHAT IS FINANCIAL INTEGRITY?

A. Financial integrity refers to the Company's ability to obtain required funding throughout an economic cycle, which is critical to the Company's obligation to provide utility services. Financial integrity allows Public Service to maintain access to the capital markets at all times and at a reasonable cost. A lack of financial integrity can limit a company's ability to finance assets or undertake new projects, particularly during times of capital market volatility. Financial integrity ensures that the Company will have the flexibility to withstand unanticipated macro-economic events that are outside of its control.

Q. WHY SHOULD THE COMMISSION BE CONCERNED ABOUT PUBLIC SERVICE'S FINANCIAL INTEGRITY?

A. Financial integrity supports our goal of delivering safe and reliable service at a low cost. A financially healthy utility is able to access the financial market at reasonable costs and has the flexibility to manage through difficult times when access to capital may be limited. During credit constrained periods such as occurred during the recent recession, companies with strong credit ratings were generally able to continue to issue debt at reasonable rates while companies with weaker credit ratings, even though investment grade, could only issue securities at a premium, if they were able to issue at all.

A review of the credit spreads since over the past several years shows that lower rated utilities are much more affected by difficult economic times. During the financial crisis of 2008 and 2009, the credit spread differential between comparable A-rated and BBB-rated utility bonds spiked to almost 200 basis points even though the average spread since 1991 was less than 40 basis points. A similar peak in the credit spread differential occurred during the recession in the early 2000s, although not to the same extent.

In our case, as I describe in greater detail below, our credit quality has gradually improved since 2004 but obtaining our objective of an A- corporate rating in 2010 has allowed us to consistently issue debt at very favorable rates relative to other regulated utilities.

Q. HOW IS FINANCIAL INTEGRITY MEASURED?

A. Financial integrity is primarily measured by the three major credit rating agencies - S&P, Moody's, and Fitch. These agencies annually (or more frequently if it is warranted) undertake a comprehensive quantitative and qualitative evaluation of the financial and business risks facing a company in order to determine its credit rating. For the utility industry, the business risk evaluation includes analysis of management decisions, the Company's operational performance, competitive issues, and the regulatory environment affecting the utility. Financial risk evaluates a company's corporate governance, risk management and financial policies, economic capital structure, and liquidity. The rating agencies evaluate several financial ratios to further quantify the financial risk of a company.

S&P has detailed its approach to assessing the business and financial risks of a utility in the report '*Key Credit Factors For the Regulated Utilities Industry*' published on November 19, 2013, attached as Attachment No. MPS-

1. For U.S. utilities operating in regulated environments, business risk is generally assessed as being very low, based primarily on cyclicality and competitive risk and growth. However, S&P states specifically on page 6 of its recent report that "[t]he regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk" and observes further that, "[w]e base our assessment of the regulatory framework's credit supportiveness on our view of how regulatory stability; efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return." These observations confirm how important it is for the Commission to maintain its current credit supportive policies and a stable regulatory environment.

The primary financial ratios evaluated by S&P and the other credit rating agencies include: (i) funds from operations to interest expense; (ii) funds from operations to total debt; (iii) total debt to earnings before interest, taxes, & depreciation ("EBITDA"); and (iv) total debt to total capital. These financial metrics provide a composite measure of the Company's ability to meet its financial obligations on a sustained basis.

Attachment No. MPS-2 is a short report by S&P providing its most recent update on the business risk/financial risk matrix. The three major credit rating agencies (S&P, Moody's, and Fitch) all have different ratings frameworks, but they are all similar in concept.

Q. WHAT ARE PUBLIC SERVICE'S CURRENT CREDIT RATINGS?

A. We currently have a corporate credit rating of A-, as reflected in Table 1 below.

Table 1

	S&P	**Moody's**	**Moody's S&P Equivalent***	**Fitch**
Corporate Rating	A-	A3	A-	A-
Senior Secured	A	A1	A	A+
Senior Unsecured	A-	A3	A-	A

* S&P equivalent rating of Moody's rating

Q. HAVE THERE BEEN CHANGES TO PUBLIC SERVICE'S CREDIT RATINGS SINCE THE PREVIOUSLY FILED ELECTRIC RATE CASE?

A. Yes. On January 30, 2014 Moody's upgraded Xcel Energy and Public Service and Xcel Energy Inc.'s other utility operating companies as well as several other regulated utilities across the United States. On November 13, 2013 Fitch upgraded Public Service. In each case, the relatively supportive regulatory environment that has existed in Colorado was an important driver. These reports are attached as Attachment Nos. MPS- 3 and MPS- 4.

Q. HAS THE COMPANY ALWAYS MAINTAINED THE STRONG CREDIT RATING IT HAS TODAY?

A. No, the Company was in a much weaker financial position in the mid-2000s, with a credit rating that was only one notch above junk-bond status. Starting in 2003, we undertook a number of actions focused on improving Public Service's financial strength. These included appropriately managing our balance sheet and capital structure to mitigate the impacts of imputed debt.

We also obtained approval from the Commission of our Purchase Capacity Cost Adjustment ("PCCA") that further mitigated the imputed debt effects of our purchased power agreements ("PPA"). We were able to moderate the effects of regulatory lag by obtaining approval to earn a return on construction works in progress ("CWIP") associated with Comanche 3 and by implementing certain adjustment mechanisms such as the Transmission Cost Adjustment ("TCA"), Demand Side Management Cost Adjustment ("DSMCA"), and the gas Pipeline System Integrity Adjustment ("PSIA"), and we continue to seek more current recovery of costs through our base rates and other mechanisms such as the Clean Air Clean Jobs Act ("CACJA") rider we are seeking in this proceeding.

Throughout numerous regulatory proceedings over the last 10 years, we explained our objective to position the Company to be able to access long-term capital at favorable costs throughout various economic cycles in order to fund our capital investment plans and refinance long-term debt maturities over the long term. Since 2003, the Commission has consistently supported these initiatives as we have brought them forward for approval. Collectively, these actions, have allowed us to improve and now sustain a credit rating that gives us strong access to capital markets to fund ongoing capital investments and to refinance maturing long-term debt with the goal of achieving a competitive total cost of capital.

Q. WHAT HAS BEEN THE SPECIFIC EFFECT OF IMPROVING PUBLIC SERVICE'S FINANCIAL STRENGTH?

A. Our improved financial strength has resulted in a lower overall cost of debt, which is directly passed on to customers. We were able to successfully issue $1.6 billion in long-term debt over the past three years at favorably low rates. Most recently, in March 2014, Public Service issued $300 million of 30-year first mortgage bonds that generated nearly $2 billion of investor interest. As a result of this high level of oversubscription, we were able to secure a 77 basis point spread to the 30 year U.S. Treasury benchmark, the lowest credit spread for a 30-year bond in the history of Public Service and also the tightest 30-year new issue spread for secured utility issuers in 2014. In 2015, our embedded cost of long-term debt is forecasted to be 4.68 percent – a savings of 95 basis points from the 5.63 percent debt cost approved in our last electric rate case. While the decrease is partially attributable to the low treasury yields, our strong financial health is also an important driver of this improvement as evidenced by the strong investor demand.

In addition, Public Service's credit strength provides us with timing flexibility to proactively take advantage of favorable market conditions for the benefit of our customers. For example, in 2010 as it became clear that the Commission would approve our acquisition of the Calpine generation plants, , we moved proactively to take advantage of historically low interest rates. This allowed us to successfully issue a $400 million 10-year bond at a 3.2 percent coupon rate. Similarly, during the credit crisis of 2007 and 2008, we observed the tightening credit market and we were able to accelerate our financing schedule by refinancing bonds ahead of maturity. Our strong balance sheet allowed us to take actions that may not have been possible had our credit quality been weaker.

Finally, as a result of our financial strength, we have been able to make large investments in our utility infrastructure. Over the last five years, the Company has invested approximately $3.9 billion in gas and electric utility infrastructure, including the successful completion of Comanche 3, the acquisition of the Calpine generation plants, the Pawnee-Smoky Hill transmission line, and significant investment in our natural gas distribution pipelines. In addition, as the Commission is aware we are currently in the process of implementing our Clean Air-Clean Jobs Act compliance plan, which is discussed in detail by Company witness Mr. Mark R. Fox. This plan includes a number of projects that are to go into service before December 31, 2017.

Q. IS IT IMPORTANT FOR THE COMPANY TO MAINTAIN ITS FINANCIAL HEALTH GOING FORWARD?

A. Yes. It is important for us to maintain our financial health as the Company plans to again spend approximately $4 billion in capital expenditures during the next five year period, 2014 to 2018. During the near term period 2014 and 2015, Public Service will spend close to $2.0 billion of which over 60 percent will be invested into the electric utility. The Company will need to continue to access the capital markets to issue long-term securities to finance these upcoming expenditures, and maintaining our financial health will enable us to continue to access capital markets on favorable terms relative to the market conditions at the time.

Additionally, our financial integrity is critical to maintaining access to the short-term debt markets to fund our daily utility operations including fuel inventories, and the initial phases of our construction projects. Regardless of the macro-economic conditions, we need to be in a position to access the financial markets for our short-term and long term debt needs.

We have and will continue our commitment to manage the Company's financial integrity in order maintain a reasonable overall rate of return. In this proceeding, we are recommending an overall rate of return of 7.86 percent in 2015. This would represent the second lowest authorized rate of return for any Colorado gas or electric utility over the past 30 years (based on information from Regulatory Research Associates). Only the authorized rate of return for our recently completed gas rate case is lower.

Q HOW CAN A PROCEEDING SUCH AS THIS ONE AFFECT THE COMPANY'S FINANCIAL INTEGRITY?

A. Achieving a balanced outcome in a rate proceeding such as this one is among the important factors considered by the rating agencies in assessing our credit quality going forward. While we have successfully strengthened the Company's balance sheet since 2003 through the combination of prudent management and constructive regulatory outcomes, continued diligence is necessary to ensure that the strength that has been gained is not lost so that we can to continue to access capital markets on favorable terms relative to the market conditions at the time. As the credit rating agency Fitch observed in its November 2013 report regarding its upgrade of our credit quality, "timely recovery of costs incurred will be essential towards maintaining a stable credit profile."[1] Additionally, adverse regulatory rulings contributing to deterioration in the Company's financial performance was among the factor's Moody's identified in its most recent report as having the potential to cause a ratings downgrade.

Q. HOW DO DECISIONS REGARDING PUBLIC SERVICE'S COST OF DEBT, CAPITAL STRUCTURE, AND RETURN ON EQUITY ("ROE") IN PARTICULAR AFFECT THE COMPANY'S CREDIT QUALITY AND ITS ABILITY TO CARRY OUT ITS CAPITAL INVESTMENT PLANS?

A. Decisions regarding these key financial factors affect the Company's financial strength and investment strategy in three ways:

- First, the authorized ROE and equity ratio affect our earnings and directly impact our ability to fund capital investment with internally generated funds. Internally generated funds are a significant source of investment funding for the Company, and both debt and equity investors expect the Company to be able to internally generate a substantial portion of its investment funding.
- Second, the capital structure and costs authorized directly affects all of our key credit metrics – as shown in Attachment No. MPS-9, total debt or

1 *See,* Attachment No. MPS-4 at page 2.

interest expense is a component of each of the primary credit metrics that S&P and Moody's analyze.

- Third, debt and equity investors and the credit rating agencies' perceptions regarding the regulatory environment in which we operate is an important consideration in assessing our business risk. Investors and rating agencies track the decisions of regulatory agencies relating to capital structure, cost of debt, return on equity and forward-looking cost recovery mechanisms and categorize the state regulatory environments in their assessment of the relative risks of different utility investment opportunities.

Q. HAS COLORADO TRADITIONALLY HAD A STABLE AND PREDICTABLE REGULATORY ENVIRONMENT?

A. Yes. Colorado has historically had a stable and predictable approach in regard to the significant financial issues associated with ROE, capital structure, and cost of debt that have supported the Company's credit rating and ability to raise needed capital. Prior decisions have facilitated our efforts to improve our credit quality to current levels and are consistent with supporting an A- corporate credit rating as a standalone company that issues its own debt securities.

III. CAPITAL STRUCTURE

Q. WHAT IS PUBLIC SERVICE'S RECOMMENDED CAPITAL STRUCTURE FOR THE TEST YEAR ENDING DECEMBER 31, 2015?

A. For the Test Year, we recommend a regulated equity ratio of 56 percent, which is consistent with the capital structure that was authorized in our last natural gas rate case (Proceeding No. 12AL-1268G) and in the most recent electric rate case (Proceeding No. 11AL-947E), which included a multi-year settlement through 2014. Our recommended capital structure for the Test Year is also close to our actual regulated capital structure for the twelve months ending December 31, 2013 as shown in the 2013 Historic Test Year ("HTY") presented by Ms. Blair.

As I will demonstrate later in my testimony, a 56 percent regulated equity ratio provides for the continuing financial strength of Public Service and will allow us to maintain our credit metrics within the guidelines provided by the credit rating agencies for our current credit rating.

Attachment No MPS-5 presents the Company's actual regulated capital structure for the twelve months ending December 31, 2013 and the 13-month average capital structure forecasted for 2015. The common equity balance has been adjusted to eliminate equity invested in certain non-utility plant and investments consistent with ratemaking principles adopted by the Commission in prior cases.

Q. PLEASE EXPLAIN THE RELATIONSHIP BETWEEN THE COMPANY'S REGULATED CAPITAL STRUCTURE AND THE ECONOMIC CAPITAL STRUCTURE THAT IS THE RATING AGENCIES' FOCUS IN ASSESSING PUBLIC SERVICE'S CREDIT QUALITY?

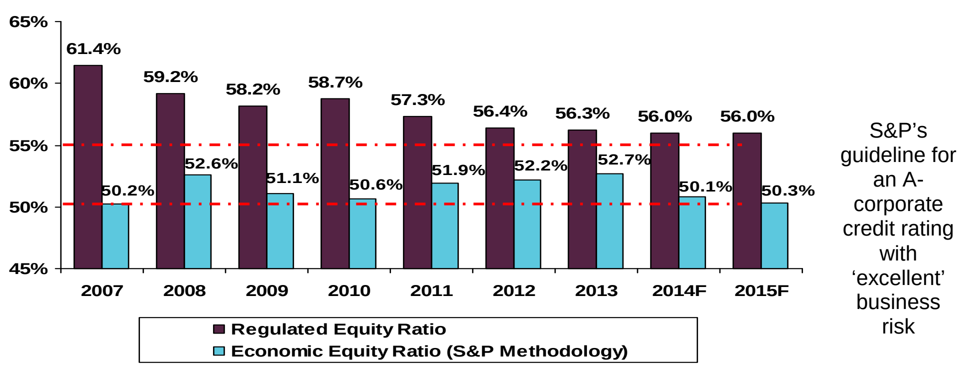
A. The economic capital structure includes all debt and debt-like instruments and therefore reflects the total financial leverage at a company. Specifically, the economic capital structure includes short-term debt, long-term debt, capital lease obligations, imputed debt from operating leases and PPAs, and common equity. Comparatively, the capital structure considered for purposes of setting our utility rates includes only our long-term debt and common equity. We manage to our economic capital structure because it is the capital structure that the credit rating agencies use in the financial assessment to determine Public Service's credit rating as it accurately reflects all of our financial obligations.

Changes to our regulated capital structure result from changes in our economic capital structure as we increase or decrease our common equity balance in order to maintain our target economic equity ratio when additional balance sheet and imputed debt is taken into account. For example, as our imputed debt balance grew in the mid-2000s due to a number of power purchase contracts, we needed to increase our common equity balance to maintain an economic equity ratio of at least 50 percent. This had the effect of increasing our regulated equity ratio to a high of 58.22 percent as recently as 2009.

As shown in Graph 1 below, our economic equity ratio has remained stable over time while our regulated equity ratio has been declining. We have made a concerted effort to reduce the level of imputed debt that we carry, which in turn has allowed us to successfully reduce our regulated equity ratio from its peak in 2007 to its Test Year projected level of 56 percent.

Graph 1

Comparison of Public Service's Regulated and Economic Equity Ratio



Q. CAN YOU BRIEFLY EXPLAIN IMPUTED DEBT?

A. As detailed in Attachment No. MPS-1 at pages 14 to 16, S&P views PPAs as fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity. S&P accounts for this debt-like obligation (reflected in both traditional fossil-fuel PPAs and in energy-only contracts typical of renewable resource PPAs) by explicitly adding a calculated amount of debt to the utility's balance sheet, the associated interest expense to the utility's income statement, and an implied amount of depreciation to the cash flow statement to calculate funds from operations. S&P accounts for the debt obligation reflected in operating leases in a similar manner except that operating leases are assigned a 100 percent risk factor rather than the lower risk factor applied to PPAs on account of the PCCA that is currently in effect. Operating leases are long-term lease obligations that are also viewed by S&P as being debt-like obligations.

Q. HAS THE COMPANY PRESENTED THIS ISSUE TO THE COMMISSION PREVIOUSLY?

A. Yes, the Company has presented this issue to the Commission in numerous proceedings since our initial identification of the issue in 2003, and we have consistently managed our capital structure by taking the effects of imputed debt into account.

Q. WHAT IS THE ASSUMED AMOUNT OF DEBT S&P WILL IMPUTE ONTO PUBLIC SERVICE'S BALANCE SHEET IN 2015?

A. Based on our analysis, in 2015 S&P will impute approximately $350 million of off balance sheet obligations comprised of $72 million related to operating leases and $272 million of debt related to power purchase agreements. This imputed debt in conjunction with all the other debt results in an economic equity ratio of 50.3 percent for 2015. The corresponding economic debt ratio of 49.7 percent on an economic basis is consistent with the S&P debt guideline for significant financial risk within the range of 45 to 50 percent. The supporting analysis is discussed in greater detail in the next section of my testimony and is attached as Attachment No. MPS-9.

Q. HAVE YOU MADE ANY CHANGES TO THE METHOD YOU ARE USING TO CALCULATE PUBLIC SERVICE'S CAPITAL STRUCTURE SINCE THE LAST ELECTRIC RATE CASE PROCEEDING?

A. Yes, we have changed the way we are calculating our long-term debt balance to more accurately reflect the actual level of debt financing available to the Company for investment and the true costs of our long-term financing during the test period. After reviewing the capital structure calculations for all of Xcel Energy's utility operating companies, we found that the methodology we have used in prior Colorado rate cases did not consistently reflect the actual costs that we incur to finance our utility investments.

Q. CAN YOU PLEASE ELABORATE ON THE CHANGE YOU MADE TO THE CAPITAL STRUCTURE CALCULATION?

A. In prior cases, the long-term debt balance was based on the par value (also referred to as principal value, nominal value, or face value) of our long-term debt outstanding. This approach, which I will refer to as the 'Par Value' method, does not accurately reflect how we are financing our utility investments because it does not account for the difference between the cash proceeds that we receive from a long-term debt issuance and the par value of the long-term debt. The method used in this case, which I will refer to as the 'Capital Employed' approach, recognizes that difference by basing the long-term debt balance on the cash proceeds (or capital available to employ) that we have available in the Test Year. Simply stated, under the 'Capital Employed' approach we use for this case, the long-term debt balance subtracts the unamortized issuance expense balance from the par value of the bond.

As shown in the example in Attachment No. MPS-6, the Capital Employed method results in a consistent representation of the Test Year costs regardless of issuance costs or debt premiums (debt issued above par value). However, this is not true with the Par Value method since the true cost of capital can be under or overstated resulting in a mismatch of revenues and expenses for the Test Year. In order to accurately reflect the relative proportions of debt and equity capital we are actually investing in our Colorado utility operations, we propose to change the methodology used to calculate our capital structure to the capital employed approach.

IV. <u>COST OF LONG-TERM DEBT</u>

Q. WHAT IS THE COMPANY'S FORECASTED EMBEDDED COST OF LONG-TERM DEBT FOR PUBLIC SERVICE FOR THE TEST YEAR?

A. For the 13 month average period at December 31, 2015, we expect the embedded cost of long-term debt to be 4.68 percent as shown in Attachment No. MPS-7, page 2. This compares to Public Service's embedded cost of long-term debt of 4.67 percent as of December 31, 2013 as shown in Attachment No. MPS-7, page 1. Our forecast for 2015 includes an assumed 30-year first mortgage bond issuance in May 2015 with a forecast coupon of 5.00 percent. The projected coupon for 2015 is based on the April 2014 Global Insights forecast of U. S. 30 year treasury rates and a credit spread based on current and historical credit spreads. We will provide the most recent Global Insights forecast and an updated credit spread for Public Service at the time we file our Rebuttal Testimony.

Consistent with prior rate case proceedings, the annual cost of debt includes our interest charges, issuance and underwriting expenses, hedge gains or losses, and the upfront fees related to our credit facility.

Q. HAVE YOU ALSO CHANGED THE METHOD USED TO CALCULATE THE COST OF LONG-TERM DEBT?

A. Yes. Consistent with the change that we made to our capital structure calculation, we have updated our cost of long-term debt calculation to more accurately reflect the test-year costs by basing the calculation on the capital employed in the Test Year. This change ensures that our cost of long-term debt is representative of the test-year period and that our capital structure and cost of long-term debt schedules are based on the same methodology.

I have provided an example in Attachment No. MPS-8 highlighting the differences between the methodology used in this rate case and the methodology used in past rate cases. While the previous method, which I refer to as the ‘Yield’ approach in the example, accurately calculates the financing costs over the life of the bond, it is not representative of the specific revenue requirements in a test year.

V. COST OF CAPITAL

Q. WHAT IS THE WEIGHTED AVERAGE COST OF CAPITAL REQUESTED FOR PUBLIC SERVICE FOR THE TEST YEAR?

A. Table 2 below shows the detail of our cost of capital of 7.86 percent as of December 31, 2013 including the actual capital structure, actual cost of debt, and the 10.35 percent cost of equity recommended by Mr. Hevert. I have also shown our proposed 7.86 percent cost of capital for 2015 based on the annual cost of long-term debt as described above and the 10.35 percent cost of equity recommended by Mr. Robert Hevert.

Table 2

Cost of Capital: 2013 Historical and Proposed for 2015 Test Year

		2013 Y/E	
	Ratio	**Rate**	**Wtd Cost**
Long-Term Debt	43.75%	4.67%	2.04%
Equity	56.25%	10.35%	5.82%
Total Cost			**7.86%**

		2015 Test Year	
	Ratio	**Rate**	**Wtd Cost**
Long-Term Debt	44.00%	4.68%	2.06%
Equity	56.00%	10.35%	5.80%
Total Cost			**7.86%**

Q. WHAT ARE THE COMPANY'S FORECASTED CREDIT METRICS UNDER THE PROPOSED CAPITAL STRUCTURE AND COST OF CAPITAL?

A. Attachment No. MPS-9 provides the calculation of the credit metrics for 2013

Actual and Projected 2014 and 2015 based on the forecast net income, funds from operations, and financial balance sheet for Public Service. This analysis assumes the Commission authorizes our proposed capital structure of 56 percent equity annual cost of long-term debt, and return on equity of 10.35 percent.

Q. HOW DO THESE METRICS COMPARE TO THE GUIDELINES ESTABLISHED BY S&P?

A. Table 3 below summarizes S&P's guidelines for the key financial metrics and Public Service's forecasted performance against those metrics. S&P's financial metrics that are shown correspond to an A- corporate rating for a company with an 'excellent' business risk rating.

Table 3

	S&P Credit Metric Guidelines for A- Corporate Rating	**Projected 2015 Credit Metrics**
Debt to Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA)	3.0x – 4.0x	3.5x
Funds from Operations to Total Debt (%)	30% - 20%	20.6%
Debt to Total Capital	45% - 50%	49.7%

Our recommended capital structure and ROE are set at a level that we believe will allow us to maintain our current rating. As shown in the table, the Funds from Operations to Total Debt is near the minimum and the Total Debt to Total Capital metric is near the maximum ranges for the A- corporate rating. If we are authorized a lower ROE or a lower regulated equity ratio than we are proposing, our metrics will likely fall below S&P's guidelines for our current credit rating.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Attachment A

Statement of Qualifications

Mary Patricia Schell

I received my Bachelor of Arts degree in Business in 1981 from the University of Minnesota - Mankato and my Master of Business Administration degree with a concentration in Accounting in 1989 from the University of Minnesota, Carlson School of Management.

My current position with Xcel Energy is Director of Corporate Financial Policy. I am responsible for implementing the financing required to achieve target capital structure objectives at each of the regulated utility operating companies, including Public Service, and at Xcel Energy, its holding company parent. I am also responsible for developing the necessary regulatory applications and testimony to gain regulatory approval for financings and support financial integrity.

I have been employed by Xcel Energy Inc. (formerly Northern States Power Company – Minnesota) since October 1991, first as Financial Analyst then progressing through various positions within the Treasury Organization to my current position.

I worked for The Pillsbury Company from 1981 through 1988 in the finance department prior to coming to Xcel Energy Inc.

I previously submitted testimony for capital structure and cost of capital in Proceeding No. 02S-315EG for Public Service Company of Colorado, the Arizona Corporation Commission for Black Mountain Gas Proceeding No. G-03703A-01-0263, and the North Dakota Public Utilities Commission under Proceeding No. PU-

400-00-521. More recently I submitted written testimony in the Public Utility Commission of Texas Proceeding No. 42004, and the New Mexico Public Regulation Commission for numerous securities authorizations.

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Key Credit Factors For The Regulated Utilities Industry

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Table Of Contents

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Table Of Contents (cont.)

Criteria | Corporates | Utilities:

Key Credit Factors For The Regulated Utilities Industry

*(**Editor's Note:** This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," published Nov. 26, 2008, "Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.)*

1. Standard & Poor's Ratings Services is refining and adapting its methodology and assumptions for its Key Credit Factors: Criteria For Regulated Utilities. We are publishing these criteria in conjunction with our corporate criteria (see "Corporate Methodology, published Nov. 19, 2013). This article relates to our criteria article, "Principles Of Credit Ratings," Feb. 16, 2011.

2. This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," Nov. 26, 2008, "Criteria: Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.

SCOPE OF THE CRITERIA

3. These criteria apply to entities where regulated utilities represent a material part of their business, other than U.S. public power, water, sewer, gas, and electric cooperative utilities that are owned by federal, state, or local governmental bodies or by ratepayers. A regulated utility is defined as a corporation that offers an essential or near-essential infrastructure product, commodity, or service with little or no practical substitute (mainly electricity, water, and gas), a business model that is shielded from competition (naturally, by law, shadow regulation, or by government policies and oversight), and is subject to comprehensive regulation by a regulatory body or implicit oversight of its rates (sometimes referred to as tariffs), service quality, and terms of service. The regulators base the rates that they set on some form of cost recovery, including an economic return on assets, rather than relying on a market price. The regulated operations can range from individual parts of the utility value chain (water, gas, and electricity networks or "grids," electricity generation, retail operations, etc.) to the entire integrated chain, from procurement to sales to the end customer. In some jurisdictions, our view of government support can also affect the final rating outcome, as per our government-related entity criteria (see "General Criteria: Rating Government-Related Entities: Methodology and Assumptions," Dec. 9, 2010).

SUMMARY OF THE CRITERIA

4. Standard & Poor's is updating its criteria for analyzing regulated utilities, applying its corporate criteria. The criteria for evaluating the competitive position of regulated utilities amend and partially supersede the "Competitive Position" section of the corporate criteria when evaluating these entities. The criteria for determining the cash flow leverage

assessment partially supersede the "Cash Flow/Leverage" section of the corporate criteria for the purpose of evaluating regulated utilities. The section on liquidity for regulated utilities partially amends existing criteria. All other sections of the corporate criteria apply to the analysis of regulated utilities.

IMPACT ON OUTSTANDING RATINGS

5. These criteria could affect the issuer credit ratings of about 5% of regulated utilities globally due primarily to the introduction of new financial benchmarks in the corporate criteria. Almost all ratings changes are expected to be no more than one notch, and most are expected to be in an upward direction.

EFFECTIVE DATE AND TRANSITION

6. These criteria are effective immediately on the date of publication.

METHODOLOGY

Part I--Business Risk Analysis

Industry risk

7. Within the framework of Standard & Poor's general criteria for assessing industry risk, we view regulated utilities as a "very low risk" industry (category '1'). We derive this assessment from our view of the segment's low risk ('2') cyclicality and very low risk ('1') competitive risk and growth assessment.

8. In our view, demand for regulated utility services typically exhibits low cyclicality, being a function of such key drivers as employment growth, household formation, and general economic trends. Pricing is non-cyclical, since it is usually based in some form on the cost of providing service.

Cyclicality

9. We assess cyclicality for regulated utilities as low risk ('2'). Utilities typically offer products and services that are essential and not easily replaceable. Based on our analysis of global Compustat data, utilities had an average peak-to-trough (PTT) decline in revenues of about 6% during recessionary periods since 1952. Over the same period, utilities had an average PTT decline in EBITDA margin of about 5% during recessionary periods, with PTT EBITDA margin declines less severe in more recent periods. The PTT drop in profitability that occurred in the most recent recession (2007-2009) was less than the long-term average.

10. With an average drop in revenues of 6% and an average profitability decline of 5%, utilities' cyclicality assessment calibrates to low risk ('2'). We generally consider that the higher the level of profitability cyclicality in an industry, the higher the credit risk of entities operating in that industry. However, the overall effect of cyclicality on an industry's risk profile may be mitigated or exacerbated by an industry's competitive and growth environment.

Competitive risk and growth

11. We view regulated utilities as warranting a very low risk ('1') competitive risk and growth assessment. For competitive risk and growth, we assess four sub-factors as low, medium, or high risk. These sub-factors are:

- Effectiveness of industry barriers to entry;
- Level and trend of industry profit margins;
- Risk of secular change and substitution by products, services, and technologies; and
- Risk in growth trends.

Effectiveness of barriers to entry--low risk

12. Barriers to entry are high. Utilities are normally shielded from direct competition. Utility services are commonly naturally monopolistic (they are not efficiently delivered through competitive channels and often require access to public thoroughfares for distribution), and so regulated utilities are granted an exclusive franchise, license, or concession to serve a specified territory in exchange for accepting an obligation to serve all customers in that area and the regulation of its rates and operations.

Level and trend of industry profit margins--low risk

13. Demand is sometimes and in some places subject to a moderate degree of seasonality, and weather conditions can significantly affect sales levels at times over the short term. However, those factors even out over time, and there is little pressure on margins if a utility can pass higher costs along to customers via higher rates.

Risk of secular change and substitution of products, services, and technologies--low risk

14. Utility products and services are not overly subject to substitution. Where substitution is possible, as in the case of natural gas, consumer behavior is usually stable and there is not a lot of switching to other fuels. Where switching does occur, cost allocation and rate design practices in the regulatory process can often mitigate this risk so that utility profitability is relatively indifferent to the substitutions.

Risk in industry growth trends--low risk

15. As noted above, regulated utilities are not highly cyclical. However, the industry is often well established and, in our view, long-range demographic trends support steady demand for essential utility services over the long term. As a result, we would expect revenue growth to generally match GDP when economic growth is positive.

B. Country risk

16. In assessing "country risk" for a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

C. Competitive position

17. In the corporate criteria, competitive position is assessed as ('1') excellent, ('2') strong, ('3') satisfactory, ('4') fair, ('5') weak, or ('6') vulnerable.

18. The analysis of competitive position includes a review of:

- Competitive advantage,
- Scale, scope, and diversity,
- Operating efficiency, and
- Profitability.

19. In the corporate criteria we assess the strength of each of the first three components. Each component is assessed as either: (1) strong, (2) strong/adequate, (3) adequate, (4) adequate/weak, or (5) weak. After assessing these components, we determine the preliminary competitive position assessment by ascribing a specific weight to each component. The applicable weightings will depend on the company's Competitive Position Group Profile. The group profile for regulated utilities is "National Industries & Utilities," with a weighting of the three components as follows: competitive advantage (60%), scale, scope, and diversity (20%), and operating efficiency (20%). Profitability is assessed by combining two sub-components: level of profitability and the volatility of profitability.

20. "Competitive advantage" cannot be measured with the same sub-factors as competitive firms because utilities are not primarily subject to influence of market forces. Therefore, these criteria supersede the "competitive advantage" section of the corporate criteria. We analyze instead a utility's "regulatory advantage" (section 1 below).

Assessing regulatory advantage

21. The regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance.

22. We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return. Our view of these four pillars is the foundation of a utility's regulatory support. We then assess the utility's business strategy, in particular its regulatory strategy and its ability to manage the tariff-setting process, to arrive at a final regulatory advantage assessment.

23. When assessing regulatory advantage, we first consider four pillars and sub-factors that we believe are key for a utility to recover all its costs, on time and in full, and earn a return on its capital employed:

24. Regulatory stability:

- Transparency of the key components of the rate setting and how these are assessed
- Predictability that lowers uncertainty for the utility and its stakeholders
- Consistency in the regulatory framework over time

25. Tariff-setting procedures and design:

- Recoverability of all operating and capital costs in full
- Balance of the interests and concerns of all stakeholders affected
- Incentives that are achievable and contained

26. Financial stability:

- Timeliness of cost recovery to avoid cash flow volatility
- Flexibility to allow for recovery of unexpected costs if they arise
- Attractiveness of the framework to attract long-term capital
- Capital support during construction to alleviate funding and cash flow pressure during periods of heavy investments

27. Regulatory independence and insulation:

- Market framework and energy policies that support long-term financeability of the utilities and that is clearly enshrined in law and separates the regulator's powers
- Risks of political intervention is absent so that the regulator can efficiently protect the utility's credit profile even during a stressful event

28. We have summarized the key characteristics of the assessments for regulatory advantage in table 1.

Table 1

Preliminary Regulatory Advantage Assessment

Qualifier	What it means	Guidance
Strong	The utility has a major regulatory advantage due to one or a combination of factors that support cost recovery and a return on capital combined with lower than average volatility of earnings and cash flows.	The utility operates in a regulatory climate that is transparent, predictable, and consistent from a credit perspective.
	There are strong prospects that the utility can sustain this advantage over the long term.	The utility can fully and timely recover all its fixed and variable operating costs, investments and capital costs (depreciation and a reasonable return on the asset base).
	This should enable the utility to withstand economic downturns and political risks better than other utilities.	The tariff set may include a pass-through mechanism for major expenses such as commodity costs, or a higher return on new assets, effectively shielding the utility from volume and input cost risks.
		Any incentives in the regulatory scheme are contained and symmetrical.
		The tariff set includes mechanisms allowing for a tariff adjustment for the timely recovery of volatile or unexpected operating and capital costs.
		There is a track record of earning a stable, compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.
		There is support of cash flows during construction of large projects, and pre-approval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs.
		The utility operates under a regulatory system that is sufficiently insulated from political intervention to efficiently protect the utility's credit risk profile even during stressful events.
Adequate	The utility has some regulatory advantages and protection, but not to the extent that it leads to a superior business model or durable benefit.	It operates in a regulatory environment that is less transparent, less predictable, and less consistent from a credit perspective.
	The utility has some but not all drivers of well-managed regulatory risk. Certain regulatory factors support the business's long-term stability and viability but could result in periods of below-average levels of profitability and greater profit volatility. However, overall these regulatory drivers are partially offset by the utility's disadvantages or lack of sustainability of other factors.	The utility is exposed to delays or is not, with sufficient certainty, able to recover all of its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on the asset base) within a reasonable time.
		Incentive ratemaking practices are asymmetrical and material, and could detract from credit quality.
		The utility is exposed to the risk that it doesn't recover unexpected or volatile costs in a full or less than timely manner due to lack of flexible reopeners or annual revenue adjustments.
		There is an uneven track record of earning a compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.

Table 1

Preliminary Regulatory Advantage Assessment (cont.)		
		There is little or no support of cash flows during construction, and investment decisions on large projects (and therefore the risk of subsequent disallowances of capital costs) rest mostly with the utility.
		The utility operates under a regulatory system that is not sufficiently insulated from political intervention and is sometimes subject to overt political influence.
Weak	The utility suffers from a complete breakdown of regulatory protection that places the utility at a significant disadvantage.	The utility operates in an opaque regulatory climate that lacks transparency, predictability, and consistency.
	The utility's regulatory risk is such that the long-term cost recovery and investment return is highly uncertain and materially delayed, leading to volatile or weak cash flows. There is the potential for material stranded assets with no prospect of recovery.	The utility cannot fully and/or timely recover its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on the asset base).
		There is a track record of earning minimal or negative rates of return in cash through various economic and political cycles and a projected inability to improve that record sustainably.
		The utility must make significant capital commitments with no solid legal basis for the full recovery of capital costs.
		Ratemaking practices actively harm credit quality.
		The utility is regularly subject to overt political influence.

29. After determining the preliminary regulatory advantage assessment, we then assess the utility's business strategy. Most importantly, this factor addresses the effectiveness of a utility's management of the regulatory risk in the jurisdiction(s) where it operates. In certain jurisdictions, a utility's regulatory strategy and its ability to manage the tariff-setting process effectively so that revenues change with costs can be a compelling regulatory risk factor. A utility's approach and strategies surrounding regulatory matters can create a durable "competitive advantage" that differentiates it from peers, especially if the risk of political intervention is high. The assessment of a utility's business strategy is informed by historical performance and its forward-looking business objectives. We evaluate these objectives in the context of industry dynamics and the regulatory climate in which the utility operates, as evaluated through the factors cited in paragraphs 24-27.

30. We modify the preliminary regulatory advantage assessment to reflect this influence positively or negatively. Where business strategy has limited effect relative to peers, we view the implications as neutral and make no adjustment. A positive assessment improves the preliminary regulatory advantage assessment by one category and indicates that management's business strategy is expected to bolster its regulatory advantage through favorable commission rulings beyond what is typical for a utility in that jurisdiction. Conversely, where management's strategy or businesses decisions result in adverse regulatory outcomes relative to peers, such as failure to achieve typical cost recovery or allowed returns, we adjust the preliminary regulatory advantage assessment one category worse. In extreme cases of poor strategic execution, the preliminary regulatory advantage assessment is adjusted by two categories worse (when possible; see table 2) to reflect management decisions that are likely to result in a significantly adverse regulatory outcome relative to peers.

Table 2

Determining The Final Regulatory Advantage Assessment

	--Strategy modifier--			
Preliminary regulatory advantage score	**Positive**	**Neutral**	**Negative**	**Very negative**
Strong	Strong	Strong	Strong/Adequate	Adequate
Strong/Adequate	Strong	Strong/Adequate	Adequate	Adequate/Weak
Adequate	Strong/Adequate	Adequate	Adequate/Weak	Weak
Adequate/Weak	Adequate	Adequate/Weak	Weak	Weak
Weak	Adequate/Weak	Weak	Weak	Weak

Scale, scope, and diversity

31. We consider the key factors for this component of competitive position to be primarily operational scale and diversity of the geographic, economic, and regulatory foot prints. We focus on a utility's markets, service territories, and diversity and the extent that these attributes can contribute to cash flow stability while dampening the effect of economic and market threats.

32. A utility that warrants a Strong or Strong/Adequate assessment has scale, scope, and diversity that support the stability of its revenues and profits by limiting its vulnerability to most combinations of adverse factors, events, or trends. The utility's significant advantages enable it to withstand economic, regional, competitive, and technological threats better than its peers. It typically is characterized by a combination of the following factors:

- A large and diverse customer base with no meaningful customer concentration risk, where residential and small to medium commercial customers typically provide most operating income.
- The utility's range of service territories and regulatory jurisdictions is better than others in the sector.
- Exposure to multiple regulatory authorities where we assess preliminary regulatory advantage to be at least Adequate. In the case of exposure to a single regulatory regime, the regulatory advantage assessment is either Strong or Strong/Adequate.
- No meaningful exposure to a single or few assets or suppliers that could hurt operations or could not easily be replaced.

33. A utility that warrants a Weak or Weak/Adequate assessment lacks scale, scope, and diversity such that it compromises the stability and sustainability of its revenues and profits. The utility's vulnerability to, or reliance on, various elements of this sub-factor is such that it is less likely than its peers to withstand economic, competitive, or technological threats. It typically is characterized by a combination of the following factors:

- A small customer base, especially if burdened by customer and/or industry concentration combined with little economic diversity and average to below-average economic prospects;
- Exposure to a single service territory and a regulatory authority with a preliminary regulatory advantage assessment of Adequate or Adequate/Weak; or
- Dependence on a single supplier or asset that cannot easily be replaced and which hurts the utility's operations.

34. We generally believe a larger service territory with a diverse customer base and average to above-average economic growth prospects provides a utility with cushion and flexibility in the recovery of operating costs and ongoing investment (including replacement and growth capital spending), as well as lessening the effect of external shocks (i.e.,

extreme local weather) since the incremental effect on each customer declines as the scale increases.

35. We consider residential and small commercial customers as having more stable usage patterns and being less exposed to periodic economic weakness, even after accounting for some weather-driven usage variability. Significant industrial exposure along with a local economy that largely depends on one or few cyclical industries potentially contributes to the cyclicality of a utility's load and financial performance, magnifying the effect of an economic downturn.

36. A utility's cash flow generation and stability can benefit from operating in multiple geographic regions that exhibit average to better than average levels of wealth, employment, and growth that underpin the local economy and support long-term growth. Where operations are in a single geographic region, the risk can be ameliorated if the region is sufficiently large, demonstrates economic diversity, and has at least average demographic characteristics.

37. The detriment of operating in a single large geographic area is subject to the strength of regulatory assessment. Where a utility operates in a single large geographic area and has a strong regulatory assessment, the benefit of diversity can be incremental.

Operating efficiency

38. We consider the key factors for this component of competitive position to be:

- Compliance with the terms of its operating license, including safety, reliability, and environmental standards;
- Cost management; and
- Capital spending: scale, scope, and management.

39. Relative to peers, we analyze how successful a utility management achieves the above factors within the levels allowed by the regulator in a manner that promotes cash flow stability. We consider how management of these factors reduces the prospect of penalties for noncompliance, operating costs being greater than allowed, and capital projects running over budget and time, which could hurt full cost recovery.

40. The relative importance of the above three factors, particularly cost and capital spending management, is determined by the type of regulation under which the utility operates. Utilities operating under robust "cost plus" regimes tend to be more insulated given the high degree of confidence costs will invariably be passed through to customers. Utilities operating under incentive-based regimes are likely to be more sensitive to achieving regulatory standards. This is particularly so in the regulatory regimes that involve active consultation between regulator and utility and market testing as opposed to just handing down an outcome on a more arbitrary basis.

41. In some jurisdictions, the absolute performance standards are less relevant than how the utility performs against the regulator's performance benchmarks. It is this performance that will drive any penalties or incentive payments and can be a determinant of the utilities' credibility on operating and asset-management plans with its regulator.

42. Therefore, we consider that utilities that perform these functions well are more likely to consistently achieve determinations that maximize the likelihood of cost recovery and full inclusion of capital spending in their asset bases. Where regulatory resets are more at the discretion of the utility, effective cost management, including of labor, may allow for more control over the timing and magnitude of rate filings to maximize the chances of a constructive outcome such as full operational and capital cost recovery while protecting against reputational risks.

43. A regulated utility that warrants a Strong or Strong/Adequate assessment for operating efficiency relative to peers generates revenues and profits through minimizing costs, increasing efficiencies, and asset utilization. It typically is characterized by a combination of the following:

- High safety record;
- Service reliability is strong, with a track record of meeting operating performance requirements of stakeholders, including those of regulators. Moreover, the utility's asset profile (including age and technology) is such that we have confidence that it could sustain favorable performance against targets;
- Where applicable, the utility is well-placed to meet current and potential future environmental standards;
- Management maintains very good cost control. Utilities with the highest assessment for operating efficiency have shown an ability to manage both their fixed and variable costs in line with regulatory expectations (including labor and working capital management being in line with regulator's allowed collection cycles); or
- There is a history of a high level of project management execution in capital spending programs, including large one-time projects, almost invariably within regulatory allowances for timing and budget.

44. A regulated utility that warrants an Adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that support profit sustainability combined with average volatility. Its cost structure is similar to its peers. It typically is characterized by a combination of the following factors:

- High safety performance;
- Service reliability is satisfactory with a track record of mostly meeting operating performance requirements of stakeholders, including those of regulators. We have confidence that a favorable performance against targets can be mostly sustained;
- Where applicable, the utility may be challenged to comply with current and future environmental standards that could increase in the medium term;
- Management maintains adequate cost control. Utilities that we assess as having adequate operating efficiency mostly manage their fixed and variable costs in line with regulatory expectations (including labor and working capital management being mostly in line with regulator's allowed collection cycles); or
- There is a history of adequate project management skills in capital spending programs within regulatory allowances for timing and budget.

45. A regulated utility that warrants a weak or weak/adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that fail to support profit sustainability combined with below-average volatility. Its cost structure is worse than its peers. It typically is characterized by a combination of the following:

- Poor safety performance;
- Service reliability has been sporadic or non-existent with a track record of not meeting operating performance requirements of stakeholders, including those of regulators. We do not believe the utility can consistently meet performance targets without additional capital spending;
- Where applicable, the utility is challenged to comply with current environmental standards and is highly vulnerable to more onerous standards;
- Management typically exceeds operating costs authorized by regulators;
- Inconsistent project management skills as evidenced by cost overruns and delays including for maintenance capital spending; or
- The capital spending program is large and complex and falls into the weak or weak/adequate assessment, even if

operating efficiency is generally otherwise considered adequate.

Profitability

46. A utility with above-average profitability would, relative to its peers, generally earn a rate of return at or above what regulators authorize and have minimal exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations. Conversely, a utility with below-average profitability would generally earn rates of return well below the authorized return relative to its peers or have significant exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations.

47. The profitability assessment consists of "level of profitability" and "volatility of profitability."

Level of profitability

48. Key measures of general profitability for regulated utilities commonly include ratios, which we compare both with those of peers and those of companies in other industries to reflect different countries' regulatory frameworks and business environments:

- EBITDA margin,
- Return on capital (ROC), and
- Return on equity (ROE).

49. In many cases, EBITDA as a percentage of sales (i.e., EBITDA margin) is a key indicator of profitability. This is because the book value of capital does not always reflect true earning potential, for example when governments privatize or restructure incumbent state-owned utilities. Regulatory capital values can vary with those of reported capital because regulatory capital values are not inflation-indexed and could be subject to different assumptions concerning depreciation. In general, a country's inflation rate or required rate of return on equity investment is closely linked to a utility company's profitability. We do not adjust our analysis for these factors, because we can make our assessment through a peer comparison.

50. For regulated utilities subject to full cost-of-service regulation and return-on-investment requirements, we normally measure profitability using ROE, the ratio of net income available for common stockholders to average common equity. When setting rates, the regulator ultimately bases its decision on an authorized ROE. However, different factors such as variances in costs and usage may influence the return a utility is actually able to earn, and consequently our analysis of profitability for cost-of-service-based utilities centers on the utility's ability to consistently earn the authorized ROE.

51. We will use return on capital when pass-through costs distort profit margins--for instance congestion revenues or collection of third-party revenues. This is also the case when the utility uses accelerated depreciation of assets, which in our view might not be sustainable in the long run.

Volatility of profitability

52. We may observe a clear difference between the volatility of actual profitability and the volatility of underlying regulatory profitability. In these cases, we could use the regulatory accounts as a proxy to judge the stability of earnings.

53. We use actual returns to calculate the standard error of regression for regulated utility issuers (only if there are at least

seven years of historical annual data to ensure meaningful results). If we believe recurring mergers and acquisitions or currency fluctuations affect the results, we may make adjustments.

Part II--Financial Risk Analysis

D. Accounting

54. Our analysis of a company's financial statements begins with a review of the accounting to determine whether the statements accurately measure a company's performance and position relative to its peers and the larger universe of corporate entities. To allow for globally consistent and comparable financial analyses, our rating analysis may include quantitative adjustments to a company's reported results. These adjustments also align a company's reported figures with our view of underlying economic conditions and give us a more accurate portrayal of a company's ongoing business. We discuss adjustments that pertain broadly to all corporate sectors, including this sector, in "Corporate Methodology: Ratios And Adjustments." Accounting characteristics and analytical adjustments unique to this sector are discussed below.

Accounting characteristics

55. Some important accounting practices for utilities include:

- For integrated electric utilities that meet native load obligations in part with third-party power contracts, we use our purchased power methodology to adjust measures for the debt-like obligation such contracts represent (see below).
- Due to distortions in leverage measures from the substantial seasonal working-capital requirements of natural gas distribution utilities, we adjust inventory and debt balances by netting the value of inventory against outstanding short-term borrowings. This adjustment provides an accurate view of the company's balance sheet by reducing seasonal debt balances when we see a very high certainty of near-term cost recovery (see below).
- We deconsolidate securitized debt (and associated revenues and expenses) that has been accorded specialized recovery provisions (see below).
- For water utilities that report under U.K. GAAP, we adjust ratios for infrastructure renewals accounting, which permits water companies to capitalize the maintenance spending on their infrastructure assets (see below). The adjustments aim to make those water companies that report under U.K. GAAP more comparable to those that report under accounting regimes that do not permit infrastructure renewals accounting.

56. In the U.S. and selectively in other regions, utilities employ "regulatory accounting," which permits a rate-regulated company to defer some revenues and expenses to match the timing of the recognition of those items in rates as determined by regulators. A utility subject to regulatory accounting will therefore have assets and liabilities on its books that an unregulated corporation, or even regulated utilities in many other global regions, cannot record. We do not adjust GAAP earnings or balance-sheet figures to remove the effects of regulatory accounting. However, as more countries adopt International Financial Reporting Standards (IFRS), the use of regulatory accounting will become more scarce. IFRS does not currently provide for any recognition of the effects of rate regulation for financial reporting purposes, but it is considering the use of regulatory accounting. We do not anticipate altering our fundamental financial analysis of utilities because of the use or non-use of regulatory accounting. We will continue to analyze the effects of regulatory actions on a utility's financial health.

Purchased power adjustment

57. We view long-term purchased power agreements (PPA) as creating fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity. By adjusting financial measures to incorporate PPA fixed obligations, we achieve greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy new load. PPAs do benefit utilities by shifting various risks to the electricity generators, such as construction risk and most of the operating risk. The principal risk borne by a utility that relies on PPAs is recovering the costs of the financial obligation in rates. (See "Standard & Poor's Methodology For Imputing Debt for U.S. Utilities' Power Purchase Agreements," May 7, 2007, for more background and information on the adjustment.)

58. We calculate the present value (PV) of the future stream of capacity payments under the contracts as reported in the financial statement footnotes or as supplied directly by the company. The discount rate used is the same as the one used in the operating lease adjustment, i.e., 7%. For U.S. companies, notes to the financial statements enumerate capacity payments for the coming five years, and a thereafter period. Company forecasts show the detail underlying the thereafter amount, or we divide the amount reported as thereafter by the average of the capacity payments in the preceding five years to get an approximation of annual payments after year five.

59. We also consider new contracts that will start during the forecast period. The company provides us the information regarding these contracts. If these contracts represent extensions of existing PPAs, they are immediately included in the PV calculation. However, a contract sometimes is executed in anticipation of incremental future needs, so the energy will not flow until some later period and there are no interim payments. In these instances, we incorporate that contract in our projections, starting in the year that energy deliveries begin under the contract. The projected PPA debt is included in projected ratios as a current rating factor, even though it is not included in the current-year ratio calculations.

60. The PV is adjusted to reflect regulatory or legislative cost-recovery mechanisms when present. Where there is no explicit regulatory or legislative recovery of PPA costs, as in most European countries, the PV may be adjusted for other mitigating factors that reduce the risk of the PPAs to the utility, such as a limited economic importance of the PPAs to the utility's overall portfolio.The adjustment reduces the debt-equivalent amount by multiplying the PV by a specific risk factor.

61. Risk factors based on regulatory or legislative cost recovery typically range between 0% and 50%, but can be as high as 100%. A 100% risk factor would signify that substantially all risk related to contractual obligations rests on the company, with no regulatory or legislative support. A 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers, as when the utility merely acts as a conduit for the delivery of a third party's electricity. These utilities are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties that act as intermediaries between retail customers and electricity suppliers. We employ a 50% risk factor in cases where regulators use base rates for the recovery of the fixed PPA costs. If a regulator has established a separate adjustment mechanism for recovery of all prudent PPA costs, a risk factor of 25% is employed. In certain jurisdictions, true-up mechanisms are more favorable and frequent than the review of base rates, but still do not amount to pure fuel adjustment clauses. Such mechanisms may be triggered by financial thresholds or passage of prescribed periods of time. In these instances, a risk factor between 25% and 50% is

employed. Specialized, legislatively created cost-recovery mechanisms may lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors. We also exclude short-term PPAs where they serve merely as gap fillers, pending either the construction of new capacity or the execution of long-term PPAs.

62. Where there is no explicit regulatory or legislative recovery of PPA costs, the risk factor is generally 100%. We may use a lower risk factor if mitigating factors reduce the risk of the PPAs on the utility. Mitigating factors include a long position in owned generation capacity relative to the utility's customer supply needs that limits the importance of the PPAs to the utility or the ability to resell power in a highly liquid market at minimal loss. A utility with surplus owned generation capacity would be assigned a risk factor of less than 100%, generally 50% or lower, because we would assess its reliance on PPAs as limited. For fixed capacity payments under PPAs related to renewable power, we use a risk factor of less than 100% if the utility benefits from government subsidies. The risk factor reflects the degree of regulatory recovery through the government subsidy.

63. Given the long-term mandate of electric utilities to meet their customers' demand for electricity, and also to enable comparison of companies with different contract lengths, we may use an evergreening methodology. Evergreen treatment extends the duration of short- and intermediate-term contracts to a common length of about 12 years. To quantify the cost of the extended capacity, we use empirical data regarding the cost of developing new peaking capacity, incorporating regional differences. The cost of new capacity is translated into a dollars-per-kilowatt-year figure using a proxy weighted-average cost of capital and a proxy capital recovery period.

64. Some PPAs are treated as operating leases for accounting purposes--based on the tenor of the PPA or the residual value of the asset on the PPA's expiration. We accord PPA treatment to those obligations, in lieu of lease treatment; rather, the PV of the stream of capacity payments associated with these PPAs is reduced to reflect the applicable risk factor.

65. Long-term transmission contracts can also substitute for new generation, and, accordingly, may fall under our PPA methodology. We sometimes view these types of transmission arrangements as extensions of the power plants to which they are connected or the markets that they serve. Accordingly, we impute debt for the fixed costs associated with such transmission contracts.

66. Adjustment procedures:

- Data requirements:
- Future capacity payments obtained from the financial statement footnotes or from management.
- Discount rate: 7%.
- Analytically determined risk factor.

- Calculations:
- Balance sheet debt is increased by the PV of the stream of capacity payments multiplied by the risk factor.
- Equity is not adjusted because the recharacterization of the PPA implies the creation of an asset, which offsets the debt.
- Property, plant, and equipment and total assets are increased for the implied creation of an asset equivalent to the

debt.

- An implied interest expense for the imputed debt is determined by multiplying the discount rate by the amount of imputed debt (or average PPA imputed debt, if there is fluctuation of the level), and is added to interest expense.
- We impute a depreciation component to PPAs. The depreciation component is determined by multiplying the relevant year's capacity payment by the risk factor and then subtracting the implied PPA-related interest for that year. Accordingly, the impact of PPAs on cash flow measures is tempered.
- The cost amount attributed to depreciation is reclassified as capital spending, thereby increasing operating cash flow and funds from operations (FFO).
- Some PPA contracts refer only to a single, all-in energy price. We identify an implied capacity price within such an all-in energy price, to determine an implied capacity payment associated with the PPA. This implied capacity payment is expressed in dollars per kilowatt-year, multiplied by the number of kilowatts under contract. (In cases that exhibit markedly different capacity factors, such as wind power, the relation of capacity payment to the all-in charge is adjusted accordingly.)
- Operating income before depreciation and amortization (D&A) and EBITDA are increased for the imputed interest expense and imputed depreciation component, the total of which equals the entire amount paid for PPA (subject to the risk factor).
- Operating income after D&A and EBIT are increased for interest expense.

Natural gas inventory adjustment

67. In jurisdictions where a pass-through mechanism is used to recover purchased natural gas costs of gas distribution utilities within one year, we adjust for seasonal changes in short-debt tied to building inventories of natural gas in non-peak periods for later use to meet peak loads in peak months. Such short-term debt is not considered to be part of the utility's permanent capital. Any history of non-trivial disallowances of purchased gas costs would preclude the use of this adjustment. The accounting of natural gas inventories and associated short-term debt used to finance the purchases must be segregated from other trading activities.

68. Adjustment procedures:

- Data requirements:
- Short-term debt amount associated with seasonal purchases of natural gas devoted to meeting peak-load needs of captive utility customers (obtained from the company).

- Calculations:
- Adjustment to debt--we subtract the identified short-term debt from total debt.

Securitized debt adjustment

69. For regulated utilities, we deconsolidate debt (and associated revenues and expenses) that the utility issues as part of a securitization of costs that have been segregated for specialized recovery by the government entity constitutionally authorized to mandate such recovery if the securitization structure contains a number of protective features:

- An irrevocable, non-bypassable charge and an absolute transfer and first-priority security interest in transition property;
- Periodic adjustments ("true-up") of the charge to remediate over- or under-collections compared with the debt service obligation. The true-up ensures collections match debt service over time and do not diverge significantly in the short run; and,
- Reserve accounts to cover any temporary short-term shortfall in collections.

70. Full cost recovery is in most instances mandated by statute. Examples of securitized costs include "stranded costs" (above-market utility costs that are deemed unrecoverable when a transition from regulation to competition occurs) and unusually large restoration costs following a major weather event such as a hurricane. If the defined features are present, the securitization effectively makes all consumers responsible for principal and interest payments, and the utility is simply a pass-through entity for servicing the debt. We therefore remove the debt and related revenues and expenses from our measures. (See "Securitizing Stranded Costs," Jan. 18, 2001, for background information.)

71. Adjustment procedures:

- Data requirements:
- Amount of securitized debt on the utility's balance sheet at period end;
- Interest expense related to securitized debt for the period; and
- Principal payments on securitized debt during the period.

- Calculations:
- Adjustment to debt: We subtract the securitized debt from total debt.
- Adjustment to revenues: We reduce revenue allocated to securitized debt principal and interest. The adjustment is the sum of interest and principal payments made during the year.
- Adjustment to operating income after depreciation and amortization (D&A) and EBIT: We reduce D&A related to the securitized debt, which is assumed to equal the principal payments during the period. As a result, the reduction to operating income after D&A is only for the interest portion.
- Adjustment to interest expense: We remove the interest expense of the securitized debt from total interest expense.

- Operating cash flows:
- We reduce operating cash flows for revenues and increase for the assumed interest amount related to the securitized debt. This results in a net decrease to operating cash flows equal to the principal repayment amount.

Infrastructure renewals expenditure

72. In England and Wales, water utilities can report under either IFRS or U.K. GAAP. Those that report under U.K. GAAP are allowed to adopt infrastructure renewals accounting, which enables the companies to capitalize the maintenance spending on their underground assets, called infrastructure renewals expenditure (IRE). Under IFRS, infrastructure renewals accounting is not permitted and maintenance expenditure is charged to earnings in the year incurred. This difference typically results in lower adjusted operating cash flows for those companies that report maintenance expenditure as an operating cash flow under IFRS, than for those that report it as capital expenditure under U.K. GAAP. We therefore make financial adjustments to amounts reported by water issuers that apply U.K. GAAP, with the aim of making ratios more comparable with those issuers that report under IFRS and U.S. GAAP. For example, we deduct IRE from EBITDA and FFO.

73. IRE does not always consist entirely of maintenance expenditure that would be expensed under IFRS. A portion of IRE can relate to costs that would be eligible for capitalization as they meet the recognition criteria for a new fixed asset set out in International Accounting Standard 16 that addresses property, plant, and equipment. In such cases, we may refine our adjustment to U.K. GAAP companies so that we only deduct from FFO the portion of IRE that would not be capitalized under IFRS. However, the information to make such a refinement would need to be of high quality, reliable, and ideally independently verified by a third party, such as the company's auditor. In the absence of this, we assume

that the entire amount of IRE would have been expensed under IFRS and we accordingly deduct the full expenditure from FFO.

74. Adjustment procedures:

- Data requirements:
- U.K. GAAP accounts typically provide little information on the portion of capital spending that relates to renewals accounting, or the related depreciation, which is referred to as the infrastructure renewals charge. The information we use for our adjustments is, however, found in the regulatory cost accounts submitted annually by the water companies to the Water Services Regulation Authority, which regulates all water companies in England and Wales.

- Calculations:
- EBITDA: Reduced by the value of IRE that was capitalized in the period.
- EBIT: Adjusted for the difference between the adjustment to EBITDA and the reduction in the depreciation expense, depending on the degree to which the actual cash spending in the current year matches the planned spending over the five-year regulatory review period.
- Cash flow from operations and FFO: Reduced by the value of IRE that was capitalized in the period.
- Capital spending: Reduced by the value of infrastructure renewals spending that we reclassify to cash flow from operations.
- Free operating cash flow: No impact, as the reduction in operating cash flows is exactly offset by the reduction in capital spending.

E. Cash flow/leverage analysis

75. In assessing the cash flow adequacy of a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology"). We assess cash flow/leverage on a six-point scale ranging from ('1') minimal to ('6') highly leveraged. These scores are determined by aggregating the assessments of a range of credit ratios, predominantly cash flow-based, which complement each other by focusing attention on the different levels of a company's cash flow waterfall in relation to its obligations.

76. The corporate methodology provides benchmark ranges for various cash flow ratios we associate with different cash flow leverage assessments for standard volatility, medial volatility, and low volatility industries. The tables of benchmark ratios differ for a given ratio and cash flow leverage assessment along two dimensions: the starting point for the ratio range and the width of the ratio range.

77. If an industry's volatility levels are low, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment are less stringent, although the width of the ratio range is narrower. Conversely, if an industry has standard levels of volatility, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment may be elevated, but with a wider range of values.

78. We apply the "low-volatility" table to regulated utilities that qualify under the corporate criteria and with all of the following characteristics:

- A vast majority of operating cash flows come from regulated operations that are predominantly at the low end of the utility risk spectrum (e.g., a "network," or distribution/transmission business unexposed to commodity risk and with very low operating risk);
- A "strong" regulatory advantage assessment;

- An established track record of normally stable credit measures that is expected to continue;
- A demonstrated long-term track record of low funding costs (credit spread) for long-term debt that is expected to continue; and
- Non-utility activities that are in a separate part of the group (as defined in our group rating methodology) that we consider to have "nonstrategic" group status and are not deemed high risk and/or volatile.

79. We apply the "medial volatility" table to companies that do not qualify under paragraph 78 with:

- A majority of operating cash flows from regulated activities with an "adequate" or better regulatory advantage assessment; or
- About one-third or more of consolidated operating cash flow comes from regulated utility activities with a "strong" regulatory advantage and where the average of its remaining activities have a competitive position assessment of '3' or better.

80. We apply the "standard-volatility" table to companies that do not qualify under paragraph 79 and with either:

- About one-third or less of its operating cash flow comes from regulated utility activities, regardless of its regulatory advantage assessment; or
- A regulatory advantage assessment of "adequate/weak" or "weak."

Part III--Rating Modifiers

F. Diversification/portfolio effect

81. In assessing the diversification/portfolio effect on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

G. Capital structure

82. In assessing the quality of the capital structure of a regulated utility, we use the same methodology as with other corporate issuers (see "Corporate Methodology").

H. Liquidity

83. In assessing a utility's liquidity/short-term factors, our analysis is consistent with the methodology that applies to corporate issuers (See "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," Nov. 19, 2013) except for the standards for "adequate" liquidity set out in paragraph 84 below.

84. The relative certainty of financial performance by utilities operating under relatively predictable regulatory monopoly frameworks make these utilities attractive to investors even in times of economic stress and market turbulence compared to conventional industrials. For this reason, utilities with business risk profiles of at least "satisfactory" meet our definition of "adequate" liquidity based on a slightly lower ratio of sources to uses of funds of 1.1x compared with the standard 1.2x. Also, recognizing the cash flow stability of regulated utilities we allow more discretion when calculating covenant headroom. We consider that utilities have adequate liquidity if they generate positive sources over uses, even if forecast EBITDA declines by 10% (compared with the 15% benchmark for corporate issuers) before covenants are breached.

I. Financial policy

85. In assessing financial policy on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

J. Management and governance

86. In assessing management and governance on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

K. Comparable ratings analysis

87. In assessing the comparable ratings analysis on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

Appendix--Frequently Asked Questions

Does Standard & Poor's expect that the business strategy modifier to the preliminary regulatory advantage will be used extensively?

88. Globally, we expect management's influence will be neutral in most jurisdictions. Where the regulatory assessment is "strong," it is less likely that a negative business strategy modifier would be used due to the nature of the regulatory regime that led to the "strong" assessment in the first place. Utilities in "adequate/weak" and "weak" regulatory regimes are challenged to outperform due to the uncertainty of such regulatory regimes. For a positive use of the business strategy modifier, there would need to be a track record of the utility consistently outperforming the parameters laid down under a regulatory regime, and we would need to believe this could be sustained. The business strategy modifier is most likely to be used when the preliminary regulatory advantage assessment is "strong/adequate" because the starting point in the assessment is reasonably supportive, and a utility has shown it manages regulatory risk better or worse than its peers in that regulatory environment and we expect that advantage or disadvantage will persist. An example would be a utility that can consistently earn or exceed its authorized return in a jurisdiction where most other utilities struggle to do so. If a utility is treated differently by a regulator due to perceptions of poor customer service or reliability and the "operating efficiency" component of the competitive position assessment does not fully capture the effect on the business risk profile, a negative business strategy modifier could be used to accurately incorporate it into our analysis. We expect very few utilities will be assigned a "very negative" business strategy modifier.

Does a relatively strong or poor relationship between the utility and its regulator compared with its peers in the same jurisdiction necessarily result in a positive or negative adjustment to the preliminary regulatory advantage assessment?

89. No. The business strategy modifier is used to differentiate a company's regulatory advantage within a jurisdiction where we believe management's business strategy has and will positively or negatively affect regulatory outcomes beyond what is typical for other utilities in that jurisdiction. For instance, in a regulatory jurisdiction where allowed returns are negotiated rather than set by formula, a utility that is consistently authorized higher returns (and is able to earn that return) could warrant a positive adjustment. A management team that cannot negotiate an approved capital spending program to improve its operating performance could be assessed negatively if its performance lags behind peers in the same regulatory jurisdiction.

What is your definition of regulatory jurisdiction?

90. A regulatory jurisdiction is defined as the area over which the regulator has oversight and could include single or multiple subsectors (water, gas, and power). A geographic region may have several regulatory jurisdictions. For example, the Office of Gas and Electricity Markets and the Water Services Regulation Authority in the U.K. are considered separate regulatory jurisdictions. In Ontario, Canada, the Ontario Energy Board represents a single jurisdiction with regulatory oversight for power and gas. Also, in Australia, the Australian Energy Regulator would be considered a single jurisdiction given that it is responsible for both electricity and gas transmission and distribution networks in the entire country, with the exception of Western Australia.

Are there examples of different preliminary regulatory advantage assessments in the same country or jurisdiction?

91. Yes. In Israel we rate a regulated integrated power utility and a regulated gas transmission system operator (TSO). The power utility's relationship with its regulator is extremely poor in our view, which led to significant cash flow volatility in a stress scenario (when terrorists blew up the gas pipeline that was then Israel's main source of natural gas, the utility was unable to negotiate compensation for expensive alternatives in its regulated tariffs). We view the gas TSO's relationship with its regulator as very supportive and stable. Because we already reflected this in very different preliminary regulatory advantage assessments, we did not modify the preliminary assessments because the two regulatory environments in Israel differ and were not the result of the companies' respective business strategies.

How is regulatory advantage assessed for utilities that are a natural monopoly but are not regulated by a regulator or a specific regulatory framework, and do you use the regulatory modifier if they achieve favorable treatment from the government as an owner?

92. The four regulatory pillars remain the same. On regulatory stability we look at the stability of the setup, with more emphasis on the historical track record and our expectations regarding future changes. In tariff-setting procedures and design we look at the utility's ability to fully recover operating costs, investments requirements, and debt-service obligations. In financial stability we look at the degree of flexibility in tariffs to counter volume risk or commodity risk. The flexibility can also relate to the level of indirect competition the utility faces. For example, while Nordic district heating companies operate under a natural monopoly, their tariff flexibility is partly restricted by customers' option to change to a different heating source if tariffs are significantly increased. Regulatory independence and insulation is mainly based on the perceived risk of political intervention to change the setup that could affect the utility's credit profile. Although political intervention tends to be mostly negative, in certain cases political ties due to state ownership might positively influence tariff determination. We believe that the four pillars effectively capture the benefits from the close relationship between the utility and the state as an owner; therefore, we do not foresee the use of the regulatory modifier.

In table 1, when describing a "strong" regulatory advantage assessment, you mention that there is support of cash flows during construction of large projects, and preapproval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs. Would this preclude a "strong" regulatory advantage assessment in jurisdictions where those practices are absent?

93. No. The table is guidance as to what we would typically expect from a regulatory framework that we would assess as "strong." We would expect some frameworks with no capital support during construction to receive a "strong" regulatory advantage assessment if in aggregate the other factors we analyze support that conclusion.

RELATED CRITERIA AND RESEARCH

- Corporate Methodology, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions, Nov. 19, 2013
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Nov. 19, 2013
- Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities and Insurers, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, Dec. 9, 2010

These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.

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Criteria Methodology: Business Risk/Financial Risk Matrix Expanded

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Table Of Contents

ARCHIVE | Criteria | Corporates | General:

Criteria Methodology: Business Risk/Financial Risk Matrix Expanded

***(Editor's Note:** This article has been superseded by "Methodology: Business Risk/Financial Risk Matrix Expanded," published Sept. 18, 2012.)*

Standard & Poor's Ratings Services is refining its methodology for corporate ratings related to its business risk/financial risk matrix, which we published as part of "2008 Corporate Ratings Criteria" on April 15, 2008, on RatingsDirect at www.ratingsdirect.com and Standard & Poor's Web site at www.standardandpoors.com.

This article amends and supersedes the criteria as published in Corporate Ratings Criteria, page 21, and the articles listed in the "Related Articles" section at the end of this report.

This article is part of a broad series of measures announced last year to enhance our governance, analytics, dissemination of information, and investor education initiatives. These initiatives are aimed at augmenting our independence, strengthening the rating process, and increasing our transparency to better serve the global markets.

We introduced the business risk/financial risk matrix four years ago. The relationships depicted in the matrix represent an essential element of our corporate analytical methodology.

We are now expanding the matrix, by adding one category to both business and financial risks (see table 1). As a result, the matrix allows for greater differentiation regarding companies rated lower than investment grade (i.e., 'BB' and below).

Table 1

Business And Financial Risk Profile Matrix

Business Risk Profile	--Financial Risk Profile--					
	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	CCC+

These rating outcomes are shown for guidance purposes only. Actual rating should be within one notch of indicated rating outcomes.

The rating outcomes refer to issuer credit ratings. The ratings indicated in each cell of the matrix are the midpoints of a range of likely rating possibilities. This range would ordinarily span one notch above and below the indicated rating.

Business Risk/Financial Risk Framework

Our corporate analytical methodology organizes the analytical process according to a common framework, and it divides the task into several categories so that all salient issues are considered. The first categories involve fundamental business analysis; the financial analysis categories follow.

Our ratings analysis starts with the assessment of the business and competitive profile of the company. Two companies with identical financial metrics can be rated very differently, to the extent that their business challenges and prospects differ. The categories underlying our business and financial risk assessments are:

Business risk

- Country risk
- Industry risk
- Competitive position
- Profitability/Peer group comparisons

Financial risk

- Accounting
- Financial governance and policies/risk tolerance
- Cash flow adequacy
- Capital structure/asset protection
- Liquidity/short-term factors

We do not have any predetermined weights for these categories. The significance of specific factors varies from situation to situation.

Updated Matrix

We developed the matrix to make explicit the rating outcomes that are typical for various business risk/financial risk combinations. It illustrates the relationship of business and financial risk profiles to the issuer credit rating.

We tend to weight business risk slightly more than financial risk when differentiating among investment-grade ratings. Conversely, we place slightly more weight on financial risk for speculative-grade issuers (see table 1, again). There also is a subtle compounding effect when both business risk and financial risk are aligned at extremes (i.e., excellent/minimal and vulnerable/highly leveraged.)

The new, more granular version of the matrix represents a refinement--not any change in rating criteria or standards--and, consequently, holds no implications for any changes to existing ratings. However, the expanded matrix should enhance the transparency of the analytical process.

Financial Benchmarks

Table 2

Financial Risk Indicative Ratios (Corporates)			
	FFO/Debt (%)	**Debt/EBITDA (x)**	**Debt/Capital (%)**
Minimal	greater than 60	less than 1.5	less than 25
Modest	45-60	1.5-2	25-35
Intermediate	30-45	2-3	35-45
Significant	20-30	3-4	45-50
Aggressive	12-20	4-5	50-60
Highly Leveraged	less than 12	greater than 5	greater than 60

How To Use The Matrix--And Its Limitations

The rating matrix indicative outcomes are what we typically observe--but are not meant to be precise indications or guarantees of future rating opinions. Positive and negative nuances in our analysis may lead to a notch higher or lower than the outcomes indicated in the various cells of the matrix.

In certain situations there may be specific, overarching risks that are outside the standard framework, e.g., a liquidity crisis, major litigation, or large acquisition. This often is the case regarding credits at the lowest end of the credit spectrum--i.e., the 'CCC' category and lower. These ratings, by definition, reflect some impending crisis or acute vulnerability, and the balanced approach that underlies the matrix framework just does not lend itself to such situations.

Similarly, some matrix cells are blank because the underlying combinations are highly unusual--and presumably would involve complicated factors and analysis.

The following hypothetical example illustrates how the tables can be used to better understand our rating process (see tables 1 and 2).

We believe that Company ABC has a satisfactory business risk profile, typical of a low investment-grade industrial issuer. If we believed its financial risk were intermediate, the expected rating outcome should be within one notch of 'BBB'. ABC's ratios of cash flow to debt (35%) and debt leverage (total debt to EBITDA of 2.5x) are indeed characteristic of intermediate financial risk.

It might be possible for Company ABC to be upgraded to the 'A' category by, for example, reducing its debt burden to the point that financial risk is viewed as minimal. Funds from operations (FFO) to debt of more than 60% and debt to EBITDA of only 1.5x would, in most cases, indicate minimal.

Conversely, ABC may choose to become more financially aggressive--perhaps it decides to reward shareholders by borrowing to repurchase its stock. It is possible that the company may fall into the 'BB' category if we view its financial risk as significant. FFO to debt of 20% and debt to EBITDA 4x would, in our view, typify the significant financial risk category.

Still, it is essential to realize that the financial benchmarks are guidelines, neither gospel nor guarantees. They can vary in nonstandard cases: For example, if a company's financial measures exhibit very little volatility, benchmarks may be somewhat more relaxed.

Moreover, our assessment of financial risk is not as simplistic as looking at a few ratios. It encompasses:

- a view of accounting and disclosure practices;
- a view of corporate governance, financial policies, and risk tolerance;
- the degree of capital intensity, flexibility regarding capital expenditures and other cash needs, including acquisitions and shareholder distributions; and
- various aspects of liquidity--including the risk of refinancing near-term maturities.

The matrix addresses a company's standalone credit profile, and does not take account of external influences, which would pertain in the case of government-related entities or subsidiaries that in our view may benefit or suffer from affiliation with a stronger or weaker group. The matrix refers only to local-currency ratings, rather than foreign-currency ratings, which incorporate additional transfer and convertibility risks. Finally, the matrix does not apply to project finance or corporate securitizations.

Related Criteria And Research

Industrials' Business Risk/Financial Risk Matrix--A Fundamental Perspective On Corporate Ratings, April 7, 2005

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's upgrades Xcel Energy and its subsidiaries; outlooks stable

Global Credit Research - 31 Jan 2014

Approximately $11.5 billion of debt affected

New York, January 31, 2014 -- Moody's Investors Service upgraded the ratings of Xcel Energy Inc. and its subsidiaries, including Xcel's Issuer Rating to A3 from Baa1; its subsidiary Northern States Power Company (Minnesota) (NSP-Minnesota)'s Issuer Rating to A2 from A3; Northern States Power Company (Wisconsin) (NSP-Wisconsin)'s senior unsecured rating to A2 from A3; Public Service Company of Colorado (PSCo)'s Issuer Rating to A3 from Baa1; and Southwestern Public Service Company (SPS)'s senior unsecured rating to Baa1 from Baa2. Moody's also upgraded NSP-Minnesota and NSP-Wisconsin's commercial paper ratings to Prime-1 from Prime-2. These rating actions complete our review of Xcel, NSP-Minnesota, NSP-Wisconsin, PSCo, and SPS initiated on November 8, 2013. The outlooks for all of these companies are stable.

RATING RATIONALE

The primary driver of today's rating action was Moody's more favorable view of the relative credit supportiveness of the US regulatory environment, as detailed in our September 2013 Request for Comment titled "Proposed Refinements to the Regulated Utilities Rating Methodology and our Evolving View of US Utility Regulation."

"Xcel's rating reflects its straightforward, low business risk profile as a sizable owner of rate-regulated utilities," said Moody's senior vice president Mihoko Manabe.

Xcel has de minimis non-utility activity that makes many of its peers riskier. Its primary credit driver, therefore, is the regulatory risk from a constant round of rate cases as it seeks to recover costs from a sustained capital spending cycle. The financial stability of Xcel's utilities, together with its conservative management strategy, contribute to very steady credit metrics. Xcel remains committed to financing its capital program in a prudent manner, using a reasonable mix of debt and equity and managing its dividend payout ratios. The Xcel holding company's rating also reflects its debt's structural subordination to a significant but manageable amount of subsidiary debt.

Moody's has historically considered NSP-Minnesota's regulatory treatment as above-average in Minnesota but anticipates some unpredictability over the near-term. The company faced some disappointments in its 2013 electric rate case and is pursuing yet another large electric case in 2014, as NSP-Minnesota readdresses some items that were not resolved in the prior proceeding. From a credit perspective, however, Moody's notes that the 2013 decision resulted in a minor increase in cash flow for the company. Furthermore, NSP-Minnesota has been granted a suite of trackers and other adjustment mechanisms that has promoted strong credit ratios that have varied little over the years.

Moody's continues to view NSP-Wisconsin's regulatory relationships as above-average among US state regulated utilities. While the Wisconsin jurisdiction is not inclined to grant trackers and other adjustment mechanisms, it provides NSP-Wisconsin with sufficient, timely rate relief through bi-annual rate cases and the use of a forward test year that help the utility to maintain its solid credit metrics.

At PSCo, a large, protracted capital program according to Colorado's Clean Air Clean Jobs Act has necessitated a rate case every year or two. The company however has been granted a majority of what it has requested in expeditious rate settlements. PSCo also has access to alternative rate making mechanisms, riders to recover pipeline replacement and certain other investments outside of a base rate case, and a forward test year, although the latter was recently denied in its recent gas case. The company plans another electric rate case in 2014, but these serial rate filings should ease after the capital expenditures related to the Clean Air Clean Jobs Act peaks this year.

Historically the small laggard within the Xcel family, SPS will become a growth area over the next five years, as that subsidiary spends about 1.5 times its current rate base to serve the frenetic activity in the local oil patch. The rate treatment in Texas and New Mexico, which has relied on rate cases based on historical test years, has resulted in regulatory lag, as indicated by SPS's cash flow metrics being lowest among the Xcel utilities. In recent years, however, both states have passed legislation that will provide greater support of credit quality, for example, forward test years in New Mexico and riders for transmission and distribution costs. These laws are being implemented in current rate cases in those states.

WHAT COULD CHANGE RATING -- UP

Longer term, Xcel's and the subsidiaries' ratings could be upgraded on their individual merits if the companies demonstrate improved financial performance, for example, CFO pre-W/C to debt above 22% on a sustainable basis. Since regulated utility activities represent an overwhelming majority of Xcel's operations, this scenario would be unlikely without more supportive regulatory outcomes for several of its subsidiaries.

WHAT COULD CHANGE RATING -- DOWN

The ratings or outlook could be revised downward if Xcel's financial performance deteriorates, for example, CFO pre-W/C to debt falling to below 17% for an extended period. Factors that could contribute to this deterioration include adverse regulatory rulings, significant operating difficulties, a more aggressive capital program, or a change to a riskier management strategy.

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in December 2013. Please see the Credit Policy page on www.moodys.com for a copy of this methodology.

Headquartered in Minneapolis, Minnesota, Xcel Energy Inc. is a utility holding company.

Actions Taken:

Xcel Energy Inc. :

LT Issuer Rating to A3 from Baa1

Senior Unsecured Rating to A3 from Baa1

Senior Unsecured Bank Credit Facility to A3 from Baa1

Senior Unsecured Shelf to (P)A3 from (P)Baa1

Subordinate Shelf to (P)Baa1 from (P)Baa2

Junior Subordinate Shelf to (P)Baa1 from (P)Baa2

Preferred Shelf to (P)Baa2 from (P)Baa3

Outlook to Stable from Under Review for Upgrade

Northern States Power Company (Minnesota):

Long Term Issuer Rating to A2 from A3

Senior Unsecured Bank Credit Facility to A2 from A3

First Mortgage Bonds to Aa3 from A1

Senior Secured Shelf to (P)Aa3 from (P)A1

Senior Unsecured Shelf to (P)A2 from (P)A3

Commercial Paper to P-1 from P-2

Outlook to Stable from Under Review for Upgrade

Northern States Power Company (Wisconsin):

Senior Unsecured Bank Credit Facility to A2 from A3

First Mortgage Bonds to Aa3 from A1

Senior Secured Shelf to (P)Aa3 from (P)A1

Senior Unsecured Shelf to (P)A2 from (P)A3

Commercial Paper to P-1 from P-2

Public Service Company of Colorado:

Long Term Issuer Rating to A3 from Baa1

Senior Unsecured Bank Credit Facility to A3 from Baa1

First Mortgage Bonds to A1 from A2

Senior Secured MTN to (P)A1 from (P)A2

Outlook to Stable from Under Review for Upgrade

Southwestern Public Service Company:

Long Term Issuer Rating to Baa1 from Baa2

Senior Unsecured Rating to Baa1 from Baa2

Senior Unsecured Bank Credit Facility to Baa1 from Baa2

First Mortgage Bonds to A2 from A3

Senior Secured Shelf to (P)A2 from (P)A3

Senior Unsecured Shelf to (P)Baa1 from (P)Baa2

Outlook to Stable from Under Review for Upgrade

REGULATORY DISCLOSURES

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Regulatory disclosures contained in this press release apply to the credit rating and, if applicable, the related rating outlook or rating review.

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Please see the ratings tab on the issuer/entity page on www.moodys.com for additional regulatory disclosures for each credit rating.

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FitchRatings

FITCH UPGRADES PSCO'S IDR TO 'A-'; AFFIRMS XEL AND SUBSIDIARIES RATINGS

Fitch Ratings-New York-14 November 2013: Fitch Ratings has upgraded the Issuer Default Rating (IDR) of Public Service Co. of Colorado (PSCo) by one notch to 'A-' from 'BBB+' and revised the Rating Outlook to Stable from Positive. Fitch has also affirmed the ratings of Xcel Energy, Inc. (XEL) and operating subsidiaries Northern States Power-Minnesota (NSPM), Northern States Power-Wisconsin (NSPW), and Southwestern Public Service Co. (SPS). The Rating Outlook is Stable. A full list of ratings is included at the end of this release. Approximately $11.19 billion of long-term debt is affected by today's rating action.

KEY RATING DRIVERS FOR XCEL ENERGY

XEL's rating affirmation reflects the relatively stable operating cash flows of its operating subsidiaries and the financial support it receives from them in the form of dividends for the payment of corporate expenses, debt service obligations, dividends to common shareholders, and for other business matters. XEL's utility subsidiaries enjoy relatively constructive regulatory frameworks across multiple jurisdictions and exhibit limited fuel and commodity price risk due to the ability to recover fuel and purchased power via separate cost trackers.

The utility subsidiaries received relatively supportive regulatory outcomes in the latest series of rate cases, notably in Colorado where PSCo reached an electric three-year multi-rate plan where step-up rate increases mitigate regulatory lag and provides regulatory predictability through 2014. In Minnesota, NSPM was granted a rate increase of $103 million effective September 2013, compared to the $209 million it had requested. The rate decision was less constructive than what Fitch had originally anticipated and materially below what NSPM has received in past orders. Fitch notes the 9.83% return on equity (ROE) authorized by the Minnesota Public Utility Commission (MPUC) was about 50 basis points below the ROE authorized in NSPM's previous rate case.

In November 2013, NSPM filed a new two-year electric rate case requesting a relatively sizeable rate increase of $291 million. Balanced outcomes in future rate proceedings at PSCo and NSPM will be critical to maintain XEL's ratings at current levels, given that the two subsidiaries account for approximately 82% of consolidated EBITDA. Fitch expects NSPW and SPS to seek ongoing rate relief over the forecast period and achieve regulatory outcomes that are consistent with the constructive rate orders from completed electric rate cases in Wisconsin, Texas, and New Mexico, where the utilities received 91%, 60%, and 68% of rate requests, respectively.

Fitch believes NSPM's pending rate proceeding carries some level of regulatory risk particularly in light of the most recent rate order. NSPM recently concluded its rate case and the filing for new rates shortly thereafter may lead to overall regulatory fatigue and customer backlash. Fitch also notes that NSPM's filing is the first rate proceeding under which the MPUC is considering a multi-year rate request, which adds some level of regulatory uncertainty, in Fitch's view.

Some of the key drivers behind the rate request are the recovery of cost overruns on the Monticello life extension and 71MW power uprate project, recovery of Sherco Unit 3 costs disallowed in the last rate case, and recovery of investments to maintain and upgrade infrastructure. NSPM had initially estimated the costs associated with the Monticello project to be $320 million, but the company's latest projections suggest a total cost of approximately $665 million. The MPUC is conducting a prudency review and a decision on cost recovery will be made within the scope of the rate case. A less than balanced outcome would be credit negative for both XEL and NSPM.

Consolidated capital expenditures remain elevated over the forecast period. Capex is projected to amount to approximately $13 billion over 2013-2017, compared with $10.89 billion spent over the last five years. Management expects that about 77% of capital investments will be allocated at NSPM and PSCo, and earmarked primarily for transmission and generation, representing 30% and 26% of consolidated capex, respectively. Successful execution of planned capex and timely recovery of costs incurred will be essential towards maintaining a stable credit profile. Fitch recognizes that the utilities have various riders in their respective regulatory jurisdictions that incentivize capital investments and mitigate regulatory lag. Fitch considers XEL's commitment to support the utilities' financing needs via equity infusions to be credit supportive.

XEL has adequate liquidity to meet its short-term funding needs. Total consolidated borrowing capacity amounts to $2.45 billion under five separate five-year bank credit facilities. XEL has access to a total of $800 million under its own credit facility of which $542 million was available as of Sept. 30, 2013. As of Sept. 30, 2013, cash on hand was $102 million. XEL also supports liquidity needs of its operating subsidiaries by participating in a company money pool where it can lend but not borrow funds from the pool. Consolidated debt maturities are considered manageable with $275 million due in 2014, $250 million due in 2015, and $650 million due in 2016, including $450 million of XEL long-term debt. Fitch expects XEL to continue to enjoy ample access to the capital markets to issue equity and refinance long-term debt as needed.

For the last 12 months (LTM) ending Sept. 30, 2013, the funds flow from operations (FFO) to total interest expense stood at 5.3x and the ratio of FFO to debt stood at 21.6%. Fitch forecasts FFO/interest expense to sustain at about 5.3x and FFO/debt to average about 20% over the five-year forecast horizon. XEL's stable credit profile and financial performance will continue to be driven by the outcome of rate cases at its operating subsidiaries and the ability of the utilities to obtain timely and adequate rate relief for planned capital investments.

RATING SENSITIVITIES

Positive Rating Actions: Funding of a large multi-year capital investment plan and the uncertainty associated with the outcome of pending rate proceedings limit prospects for a positive rating action in the near future.

Negative Rating Actions: A deterioration in the regulatory environments of Colorado or Minnesota that result in an inability to successfully execute and adequately recover large capital investments could lead to negative rating actions.

Given XEL's below-industry average dividend payout, a more aggressive dividend policy adopted by management that result in parent-level incremental leverage or a reduction in parental equity support to the utilities in the midst of heavy capex would likely result in negative rating actions.

KEY RATING DRIVERS FOR PUBLIC SERVICE CO. OF COLORADO

The upgrade of PSCo's ratings is driven by PSCo's sustained strong financial performance that result in credit metrics that are in line with Fitch's benchmark ratios for the 'A-' rating category, and consistent with Fitch's prior expectations. For the LTM ending Sept. 30, 2013, the ratios of FFO/interest expense and FFO/debt stood at 6.8x and 25.3%, respectively. Fitch forecasts FFO/interest expense to remain at or above 6.0x and FFO/debt to approximate 22% over the 2013-2017 forecast period. Fitch's projections assume PSCo will continue to achieve balanced outcomes in future rate proceedings, including the ability to settle for multi-year rate plans.

PSCo currently operates under a three-year electric rate plan that stipulates a $73 million base rate increase effective May 2012, a $16 million increase effective January 2013, and a $25 million increase effective January 2014. The multi-year rate plan provides regulatory predictability and cash flow visibility through 2014. Fitch considers the Colorado regulatory framework to be balanced and supportive of credit quality, and PSCo has historically done well in rate proceedings consistently receiving more than 50% of its rate requests. Constructive rate design mechanisms include the use of forward-looking test years, energy and natural gas cost trackers, and multiple riders for transmission, renewable energy, and natural gas pipeline integrity investments.

In December 2012, PSCo filed a multi-year rate plan requesting natural gas base rate increases of $44.8 million in 2013, $9 million in 2014, and $10.9 million in 2015. The request is based on a 10.3% ROE, a 56% common equity ratio, and a 2013 forecast test year. The company is also requesting an extension of its pipeline rider, with associated increases of $35.1 million in 2013, $26.8 million in 2014, and $24.7 million in 2015. Interim rates of $82.2 million, subject to refund, went into effect in August 2013. The ALJ issued a decision recommending a base rate increase of approximately $15 million, based on a 9.72% ROE, a 56% common equity ratio, and the use of a historical test year. A final decision by the Colorado Public Utility Commission (CPUC) is expected in December 2013. Fitch has assumed in its analysis a rate decision that is in line with the ALJ's recommendation. PSCo's gas business represents approximately 20% to 25% of total earnings.

Fitch expects capex to remain elevated throughout the forecast period. Management plans on spending a total of approximately $4.46 billion over 2013-2017, which is higher than historical norms. Key drivers of capex over the forecast period are investments associated with the Clean Air Clean Jobs Act (CACJA), projects related to gas pipeline integrity, and enhancement of the distribution system. The CACJA related projects include the shutdown of over 900MW of coal generation, the addition or conversion of over 900MW of natural gas generation, and the installation of pollution control equipment on over 700MW of coal generation. Overall project is expected to be completed by 2017 and management expects to spend approximately $685 million over the forecast period. PSCo expects to recover capex via rate cases, and recovery through a rider mechanism is also allowed by the CPUC. Estimated costs related to natural gas pipeline replacement projects amount to $765 million over the next five years, and PSCo can recover its costs through a natural gas pipeline integrity rider, which reduces the impact of regulatory lag on operating cash flows during the investment phase.

Fitch expects PSCo to finance capex in a manner that is consistent with its currently authorized capital structure, using a mix of internally generated cash flows, long-term debt issuances, and parent equity infusions. Fitch expects internally generated cash flows to fund close to 80% of capex requirements over the forecast period.

Fitch considers PSCo to have adequate liquidity to meet its short-term obligations. The company has access to a total of $700 million under a bank credit facility that expires in July 2017. At Sept. 30, 2013, PSCo had $708.5 million of available liquidity, including $693 million of unused facilities. Further strengthening liquidity, PSCo participates in a money pool with its utility affiliates NSPM and SPS. PSCo maximum borrowing limit under the money pool is $250 million, which was fully available at Sept. 30, 2013. Under the money pool arrangement, PSCo and its utility affiliates can borrow funds from XEL but cannot lend to it.

PSCo's long-term debt maturities are considered manageable with $275 million due in 2014 and $129.5 million due in 2017. Fitch expects PSCo to continue to enjoy ample access to the debt capital markets to fund capex and refinance debt maturities as they become due.

The Stable Outlook reflects Fitch's expectations that the regulated utility will continue to achieve balanced rate outcomes in future rate proceedings, including the ability to settle for multi-year rate plans.

RATING SENSITIVITIES

Positive Rating Actions: Given the upgrade of PSCo's ratings, future positive rating actions are not anticipated by Fitch.

Negative Rating Actions: Unexpected unfavorable regulatory developments that hinder PSCo's ability to recover costs associated with its sizeable capital investments could have a negative effect on ratings.

KEY RATING DRIVERS FOR NORTHERN STATES POWER MINNESOTA

NSPM's ratings reflect the low-risk nature of its regulated utility business that operate in what Fitch considers to be balanced regulatory regimes across the regulatory jurisdictions of Minnesota, North Dakota, and South Dakota. Fitch notes Minnesota represents approximately 89% of NSPM's earnings and is the main driver of the utility's financial performance.

Utility rate design is enhanced by the timely recovery of fuel and purchased power costs in all three jurisdictions. Additionally, the utilities have riders that facilitate timely recovery of environmental, renewables, and transmission-related capital investments. Utility credit quality is further enhanced by rate design mechanisms that include the use of forward-looking test years in Minnesota and North Dakota, and the ability to file for multi-year rate plans in Minnesota following an order by the MPUC in June 2013. The multi-year plan is filed as part of a general rate case and can be used for the recovery of costs related to specific capital projects and appropriate non-capital projects. A stay-out provision is in effect during the multi-year term.

On Nov. 4, 2013, NSPM filed a two-year electric rate case requesting a base rate increase of $193 million in 2014 and an additional $98 million in 2015. Those amounts are net of an $81 million reduction in depreciation expense in 2014 and an additional $36 million related to DOE refunds for settlement of various claims, which management believes lessen the impact of a rate increase on customers. The request is based on a 10.25% ROE, a 52.5% common equity ratio, and a 2014 test year. Drivers of the rate request include the recovery of nuclear operating expenses, certain Sherco Unit 3 costs that were disallowed in NSPM's last rate case, pre-approved wind investments and costs to support the transmission and distribution system. As permitted by state law, NSPM is also requesting an interim rate increase of $127 million, subject to refund, to be implemented in January 2014. Fitch expects the interim request, if granted, to support NSPM's operating cash flows during a period of peak capital spending. A decision on the interim request is expected in December 2013, and a final rate decision in the first quarter of 2015 (1Q'15).

Fitch believes NSPM's pending rate proceeding carries some level of regulatory risk, particularly in light of the most recent order which was less constructive than Fitch had expected. NSPM recently concluded a rate case where it was granted a $103 million rate increase, and the filing for new rates shortly thereafter may lead to overall regulatory fatigue and customer backlash. Fitch also notes that NSPM's filing is the first rate proceeding under which the MPUC is considering a multi-year rate request, which adds some level of regulatory uncertainty, in Fitch's view. Fitch expects the request for recovery of cost overruns associated with the Monticello life extension and extended power uprate project to be a focal point of the case. Management has publicly stated that the cost of the project evolved from an original estimate of $320 million to a final cost of $665 million. The MPUC is conducting a prudence review of those costs, and a decision will be made within the scope of the rate case. Fitch notes the uprate is pending NRC approval that the utility expects to receive by the end of 2013.

A balanced rate order will be critical for NSPM to maintain its current rating profile in light of a sizeable capital spending plan over the next five years. Fitch recognizes there is some headroom in the ratings given the utility's strong credit metrics for the current rating category. For the LTM period ending Sept. 30, 2013, the ratios of FFO/interest expense and FFO/debt stood at 6.5x and 26%, respectively. The ratios include the impact of bonus depreciation. Fitch forecasts credit metrics to remain consistent with current levels, with FFO/interest and FFO/debt to average 6.3x and 24%, respectively, over 2013-2017.

NSPM plans on spending a sizeable $5.44 billion over 2013-2017 compared with $5.27 billion over the previous five years. Capex is primarily driven by investments in infrastructure, transmission stemming from the CapX2020 project, renewable energy including recently approved owned wind generation, and nuclear generation. Management is adding two self-build wind projects in MN and ND totalling 350MW, expected to be in service by the end of 2015. The CapX2020 transmission expansion is expected to go in service in 2015 with total capital spending estimated at $745 million over 2013-2015. NSPM has transmission and renewable riders that facilitate timely recovery of capital investments.

Fitch expects capex to be funded in a manner consistent with its authorized regulatory capital structure (52.56% common equity ratio), including a mix of internally generated funds, long-term debt issuances, and parent equity infusions. Fitch views parent support as credit positive for NSPM.

NSPM has adequate liquidity to meet its short-term funding obligations with access to a total of $500 million under a bank credit facility that expires in July 2017. At Sept. 30, 2013, there was $500 million of available liquidity, including $455 million of unused facilities and $45 million of cash on hand. Liquidity is also available through participation in a money pool with its utility affiliates PSCo and SPS. NSPM has a borrowing limit of $250 million of which $195 million was unused as of Sept. 30, 2013. NSPM can receive funds from XEL but cannot lend to it under the money pool arrangement. Further adding financial flexibility, there are no long-term debt maturities until 2015 when $250 million becomes due. Fitch expects NSPM to continue to enjoy ample access to the debt capital markets to fund capex and refinance existing long-term debt.

RATING SENSITIVITIES

Positive Rating Actions: Given the uncertainty of the Minnesota pending rate case, no positive rating actions are contemplated at this time.

Negative Rating Actions: An unfavorable rate outcome in NSPM's pending rate case could lead to negative rating actions.

KEY RATING DRIVERS FOR NORTHERN STATES POWER WISCONSIN

NSPW's ratings reflect the constructive regulatory framework in Wisconsin with rate design mechanisms that are supportive of credit quality, and characterized by above-average authorized ROEs, forward looking test years, purchased gas adjustment clause and annual filings for fuel and purchased energy adjustments. The Public Service Commission of Wisconsin (PSCW) has authorized ROEs of 10.4% for both NSPW and its Wisconsin utility peer, Wisconsin Electric Power Co., in their most recent rate cases. In its last electric rate case, NSPW was granted 91% of its rate request.

NSPW has an electric case pending before the commission. The utility is seeking an electric base rate increase of $34 million and a natural gas base rate increase of $0 million, based on a 10.4% ROE and a 52.5% common equity ratio, for new rates to be effective in January 2014. The rate request is driven by investments in generation, including nuclear plants, transmission and distribution, as well as higher operating expenses. The gas rate request is primarily driven by the funding of the environmental clean-up of the Ashland site. On Oct. 4, 2013, the PSCW Staff recommended a $23.8 million electric base rate increase and a gas rate reduction of $1.1 million, based on a 10.2% ROE. A PSCW decision is anticipated in December 2013.

Fitch expects the rate outcome to be balanced and consistent with prior rate decisions. NSPW's last base rate electric and gas rate increases were approved in December 2012, and management would plan on filing a new rate case in the spring of 2014 with new rates effective in January 2015.

NSPW has strong credit metrics for the current rating category. For the LTM ending Sept. 30, 2013, the ratios of FFO/interest and FFO/debt stood at 6.6x and 30.2%, respectively. Fitch forecasts FFO/ interest and FFO/debt to average 6x and 24% over 2013-2017. Part of the decline is driven by the expiration of bonus depreciation and other tax credits.

Fitch's rating concerns relate to the relatively sizeable capital spending program over the forecast period. NSPW plans on spending a total of $1.13 billion over 2013-2017, higher than historical norms. Capex is primarily earmarked for transmission spending, including NSPW's Wisconsin portion of the CapX2020 transmission project.

Fitch expects NSPW to fund capex in a manner that is consistent with its authorized regulatory capital structure (52.37% common equity ratio), with a mix of internally generated funds, long-term debt issuances, and parent equity infusions. Fitch views the parent support as credit positive for NSPW.

NSPW has adequate liquidity to meet its short-term obligations with access to a total of $150 million under a bank credit facility that expires in July 2017. As of Sept. 30, 2013, total available liquidity was $140.5 million, including $139 million of unused facilities and $1.5 million of cash on hand. There are no long-term debt maturities through 2017.

RATING SENSITIVITIES

Positive Rating Actions: No positive rating actions are anticipated in the near future.

Negative Rating Actions: A deterioration in the Wisconsin regulatory framework, although unlikely, could pressure the ratings.

KEY RATING DRIVERS FOR SOUTHWESTERN PUBLIC SERVICE CO.

SPS's ratings are supported by its low-risk regulated utility businesses that operate in the regulatory jurisdictions of Texas and New Mexico. Texas is the main driver of financial performance given it represents approximately 74% of total earnings. Rate design mechanisms include fuel and purchased power recovery mechanisms that limit commodity risk in both jurisdictions. SPS has also riders for transmission and distribution costs in Texas. Fitch considers those regulatory regimes to be challenging from a bondholder perspective, primarily due to the reliance on historic test years in the rate setting process, as well as due to authorized electric ROEs that have been below industry average over recent years. That being said, SPS has done relatively well in rate cases. In the last Texas rate case, SPS was granted 56% of its rate request, and its last rate case in New Mexico resulted in SPS receiving 68% of ask.

On June 6, 2013, the Texas Public Utility Commission (PUC) approved a settlement, authorizing SPS a $50.8 million two-step electric rate increase. The rate increase represents approximately 56% of SPS's original request. Fitch considers the rate decision to be balanced and consistent with current ratings. The first-step increase of $37 million was implemented May 1, 2013, and an incremental $13.8 million increase was effective Sept. 1, 2013. The rate order was silent regarding the authorized ROE. The addition to rate base of approximately $702 million of incremental investments, for the period January 2010 through June 2012, was the main driver of SPS's rate request. The rate order includes a provision that SPS cannot file its next rate case prior to Jan. 1, 2014.

SPS has a pending rate case in New Mexico. The utility is requesting an electric base rate increase of $32.5 million based on a 10.25% ROE and a 53.89% common equity ratio. New rates are anticipated to be effective in 1Q'14. Fitch assumes SPS will receive a rate decision that is consistent with its recently concluded rate cases.

Fitch does not believe the August 2013 unfavorable Federal Energy Regulatory Commission (FERC) ruling, related to a 2004 Complaint case brought by Golden Spread, a wholesale customer of SPS, to have a significant impact on SPS's credit quality. SPS has recorded a pre-tax charge of $35 million in 3Q'13 associated with this matter. Fitch expects SPS to fund this amount in a balanced manner, including through a parent equity infusion.

Fitch forecast SPS's credit metrics to remain in line with the 'BBB' rating category over the forecast period. For the LTM ending Sept. 30, 2013, the ratios of debt/EBITDA and FFO/debt stood at 4.1x and 15.3%, below Fitch's benchmark ratios for the current rating category. However, Fitch recognizes the weakness is partly driven by the temporary impact from the FERC order, and projected credit metrics, absent the FERC impact, are closer in line with target ratios for the current rating category. Fitch forecasts the ratios of debt/EBITDA to be below 3.8x, and FFO/debt to be near 19% by 2016. Fitch views balanced outcomes in regulatory proceedings and effective cost control management as critical to maintain current ratings.

Capex is expected to remain elevated. SPS plans on spending a sizeable $1.84 billion over 2013-2017 compared with $1.41 billion over the five last years. Capital spending is earmarked primarily for transmission investments and construction of a fourth unit at the natural-gas fired Jones Station in Lubbock, TX. The new unit will add 168MW of capacity to the service territory. Management estimates the project to cost approximately $118 million, including AFUDC. Jones unit 4 was placed in service in May 2013. Fitch expects SPS to fund capex requirements with a balanced mix of internally generated funds, long-term debt, and equity infusion from XEL.

SPS has adequate liquidity to meet its short-term obligations with access to a total of $300 million under a five-year bank credit facility. As of Sept. 30, 2013, there was $301.1 million of available liquidity, including $300 million of unused facilities and $1.1 million of cash on hand. SPS has access to additional liquidity through its participation in the money pool. SPS has a borrowing limit of $100 million, of which $20 million was available at Sept. 30, 2013. The only long-term debt maturity over the forecast period is $200 million due in 2016, which Fitch expects SPS to refinance when due.

RATING SENSITIVITIES

Positive Rating Actions: No positive rating actions are anticipated in the near term.

Negative Rating Actions: Unfavorable regulatory developments including the inability to timely recover costs associated with SPS's large capex program would likely lead to a negative rating action.

A shift in management strategy that results in weaker financial support from XEL would pressure the ratings.

Fitch has upgraded the following ratings and revised the Outlook to Stable from Positive:

PSCo
--Issuer Default Rating (IDR) to 'A-' from 'BBB+';
--Senior secured debt to 'A+' from 'A'.

Fitch has affirmed the following ratings with a Stable Outlook:

XEL
--IDR at 'BBB+';
--Senior unsecured debt at 'BBB+';

--Short-term IDR and commercial paper (CP) at 'F2'.

NSP-MN
--IDR at 'A-';
--Senior secured debt at 'A+';
--Short-term IDR and CP at 'F2'.

NSP-WI
--IDR at 'A-'
--Senior secured debt at 'A+';
--Senior unsecured debt at 'A';
--Short-term IDR and CP at 'F2'.

La Crosse (WI) (NSP-WI)
--Unsecured resource recovery refunding revenue bonds at 'A'.

SPS
--IDR at 'BBB';
--Senior secured debt at 'A-';
--Senior unsecured debt at 'BBB+';
--Short-term IDR and CP at 'F2'.

PSCo
--Short-term IDR and CP at 'F2'.

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Applicable Criteria and Related Research:

--'Corporate Rating Methodology' (Aug. 5, 2013);
--'Recovery Ratings and Notching Criteria for Utilities' (Nov. 12, 2012);
--'Rating North American Utilities, Power, Gas, and Water Companies' (May 16, 2011);
--'Parent and Subsidiary Rating Linkage' (Aug. 5, 2013).

Applicable Criteria and Related Research:
Corporate Rating Methodology: Including Short-Term Ratings and Parent and Subsidiary Linkage
http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=715139
Recovery Ratings and Notching Criteria for Utilities
http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=693750
Rating North American Utilities, Power, Gas, and Water Companies
http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=625129
Parent and Subsidiary Rating Linkage Fitch's Approach to Rating Entities within a Corporate Group Structure
http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=714476

Public Service Company of Colorado
Cost of Capital
Actual at December 31, 2013

***This capital structure includes 2013 actual debt balance, debt cost and common equity balance.
The cost of equity is consistent with what is being proposed in this case by Robert Hevert.**

Line No.	Description	Per Books	(A) Pro Forma Adjustments	Adjusted Capital	Ratio
1	Long Term Debt	3,704,500,000	6,650,000	3,711,150,000	43.75%
2					
3	Common Equity	4,801,998,953	(30,499,948)	4,771,499,005	56.25%
4					
5	Total	8,506,498,953	(23,849,948)	8,482,649,005	100.00%
6					
7					
8					
9					
10		**Ratio**	**Cost**		
11					
12	Long Term Debt	43.75%	4.67%	2.04%	
13					
14	Common Equity	56.25%	10.35% *	5.82%	
15					
16	Total	100.00%		**7.86%**	

(A) - Adjustments:

Long Term Debt:	
(1) Notes Receivable from Subsidiaries	-
(1) Notes Payable to Subsidiaries	6,650,000
Total Long Term Debt Adjustments	6,650,000
Common Equity:	
(2) Investment in Subsidiary Companies:	(17,502,115)
(3) Subsidiary Retained Earnings	0
(4) Net Non-Utility Plant	(34,665,919)
(5) Other Investments at Cost	(1,687)
(6) Other Funds	(1,668,414)
(7) Other Comprehensive Income	23,338,187
Total Common Equity Adjustments	(30,499,948)

Public Service Company of Colorado
Cost of Capital-Capital Employed
13 month average at December 31, 2015

Line No.	Description	Per Books	(A) Pro Forma Adjustments	Adjusted Capital	Ratio
1	Long Term Debt	3,858,869,654	6,400,000	3,865,269,654	44.00%
2					
3	Common Equity	4,950,538,797	(31,048,429)	4,919,490,368	56.00%
4					
5	Total	8,809,408,451	(24,648,429)	8,784,760,022	100.00%
6					
7					
8					
9					
10		**Ratio**	**Cost**		
11					
12	Long Term Debt	44.00%	4.68%	2.06%	
13					
14	Common Equity	56.00%	10.35%	5.80%	
15					
16	Total	100.00%		**7.86%**	

(A) - Adjustments:

Long Term Debt:	
(1) Notes Receivable from Subsidiaries	0
(1) Notes Payable to Subsidiaries	6,400,000
Total Long Term Debt Adjustments	6,400,000
Common Equity:	
(2) Investment in Subsidiary Companies:	(19,205,767)
(3) Subsidiary Retained Earnings	0
(4) Net Non-Utility Plant	(34,178,847)
(5) Other Investments at Cost	(1,687)
(6) Other Funds	(1,184,360)
(7) Other Comprehensive Income	23,522,232
Total Common Equity Adjustments	(31,048,429)

Capital Structure Example: Debt Balance: Capital Employed Method vs. Par Value Method

Overview:

This example highlights the difference between the debt balance for the proposed " Capital Employed Method" vs. the "Par Value of Debt Method" used in past rate proceedings.   The Capital Employed method accurately reflects the cost of financing as it captures the difference between the principal (par value) of the bond and the actual cash proceeds the company receives after issuance expenses for underwriting fees, legal expenses, debt discounts or premiums, etc. The Par Value Method does not adjust the balance in the capital structure to account for these expenses, and as a result, the amount of debt capital (cash) that is available to actually invest in rate base will be overstated or understated.

Under the historic Par Value Method, if the cash proceeds are less than the par value, the debt ratio will overstate the true debt cash proceeds available to finance utility plant. This will result in a negative impact to the ROE because a portion of equity would be earning a debt return. If a bond is issued at a premium and the cash proceeds at issuance are greater than the par value of the bond, the debt ratio in the capital structure calculation will be lower than the true debt ratio that is financing utility plant. This will result in a greater ROE impact because a portion of debt would be earning an equity return.

For this reason, we have implemented the Capital Employed method in this rate proceeding. The methodology is consistent and representative of the actual financing costs in the test year. It does not result in a negative or positive ROE impact; rather, it matches the revenue requirements with the actual costs (debt and equity return).

Example Summary:

In Example #1, the capitalization consists of $100 in long-term debt (par value) and $100 in common equity (paid-in capital). The $100 in long-term debt has total issuance costs of 2%, or $2 resulting in cash proceeds from the bond issuance of $98. Therefore, the total cash available to finance rate base is $198. The regulated capital structure under the Par Value method would be 50.00% debt (100/200) and 50.00% equity (100/200); however, the capital structure that actually finances the asset is 49.49% debt (98/198) and 50.51% equity (100/198). This inconsistency between rate base and capitalization results in degradation of the company’s ROE. As shown, the Capital Employed method used in this case corrects the inconsistency and is representative of the actual revenue requirements needed to recover the actual costs to finance rate base.

Example #2 is the same except the bond is issued at a premium, which results in cash proceeds being in excess of the par value. As shown, this results in a positive impact to the ROE under the Par Value of Debt Method. The Capital Employed method corrects this inconsistency and again, is representative of the actual costs financing rate base.

The important point in both examples is that rate base does not equal capitalization and that the capital structure should reflect how the rate base is financed.

Capital Structure Example #1: Par Value Method vs. Capital Employed Method
Bond Issued at Par Value

Capitalization Data:

Bond Length (years)		10
Coupon		5%
Par Value of Long-Term Debt	$	100
Issuance Expenses	$	(2)
Cash Received for Debt at Issuance	$	98
Value of Common Equity		100
Issuance Expense		N/A*
Cash received for equity	$	100
Total Cash Available to Finance Rate Base	$	198

Historic Method: Regulated Capital Structure under the Par Value of Debt Method

Capital Structure		Amount	Ratio	Cost	Weighted Cost
Equity	$	100	50.00%	10.00%	5.00%
Long-Term Debt	$	100	50.00%	5.31%	2.65%
	$	200	100.00%		7.65%
				Tax Rate	38.01%
				Cost of Capital with Taxes	10.72%

Income Statement

Revenue (Revenue Requirements on Rate Base)	$	21.22
Bond Coupon	$	5.00
Amortization of Debt Issuance Costs	$	0.20
Pre-Tax Income	$	16.02
Income Taxes	$	6.09
Net Income	$	9.93
ROE		9.93%
ROE Impact		-0.07%

Proposed Method: Regulated Capital Structure under the Capital Employed Method

Capital Structure		Amount	Ratio	Cost	Weighted Cost
Equity	$	100	50.51%	10.00%	5.05%
Long-Term Debt	$	98	49.49%	5.31%	2.63%
Total	$	198	100.00%		7.68%
				Tax Rate	38.01%
				Cost of Capital with Taxes	10.77%

Income Statement

Revenue (Revenue Requirements on Rate Base)	$	21.33
Interest Expense (coupon)	$	5.00
Amortization of Debt Issuance Costs	$	0.20
Pre-Tax Income	$	16.13
Income Taxes	$	6.13
Net Income	$	10.00
ROE		10.00%
ROE Shortfall		0.00%

* Paid-in-capital is recorded as net proceeds because issuance expenses are not booked.

Capital Structure Example #2: Par Value Method vs. Capital Employed Method
Bond Issued at a Premium

Capitalization Data:

Bond Length (years)		10
Coupon		5%
Par Value of Long-Term Debt	$	100
Issued at Premium	$	4
Issuance Expense	$	(2)
Cash Received for Debt at Issuance	$	102
Value of Common Equity		100
Issuance Expense		N/A*
Cash received for equity	$	100
Total Cash Available to Finance Rate Base	$	202

Historic Method: Regulated Capital Structure under the Par Value of Debt Method

Capital Structure		Amount	Ratio	Cost	Weighted Cost
Equity	$	100	50.00%	10.00%	5.00%
Long-Term Debt	$	100	50.00%	4.71%	2.35%
	$	200	100.00%		7.35%
				Tax Rate	38.01%
				Cost of Capital with Taxes	10.42%

Income Statement

Revenue (Revenue Requirements on Rate Base)	$	21.05
Bond Coupon & Premium	$	4.60
Amortization of Debt Issuance Costs	$	0.20
Pre-Tax Income	$	16.25
Income Taxes	$	6.18
Net Income	$	10.07
ROE		10.07%
ROE Impact		0.07%

Proposed Method: Regulated Capital Structure under the Capital Employed Method

Capital Structure		Amount	Ratio	Cost	Weighted Cost
Equity	$	100	49.50%	10.00%	4.95%
Long-Term Debt	$	102	50.50%	4.71%	2.38%
Total	$	202	100.00%		7.33%
				Tax Rate	38.01%
				Cost of Capital with Taxes	10.36%

Income Statement

Revenue (Revenue Requirements on Rate Base)	$	20.93
Interest Expense (coupon)	$	4.60
Amortization of Debt Issuance Costs	$	0.20
Pre-Tax Income	$	16.13
Income Taxes	$	6.13
Net Income	$	10.00
ROE		10.00%
ROE Shortfall		0.00%

* Paid-in-capital is recorded as net proceeds because issuance expenses are not booked.

PUBLIC SERVICE COMPANY OF COLORADO
Cost of Long Term Debt
at December 31, 2013

Bonds		Date of Offering	Date of Maturity	Interest Rate	Principal Amount of Issue	Premium or (Discount)	Hedging Gain (Loss)	Gross Proceeds	Underwriting Commission and Other Expenses	Gain or (Loss) on Reacquired Debt	Net Proceeds Amount	Net Proceeds Per Unit	Principal Amount Outstanding	12 Month Outstanding	Cost of Money & Yield to Maturity	12 Month Average Annualized Cost	
5.50% April	S	9/9/2003	4/1/2014	5.500%	275,000,000	(2,032,250)	25,875,735	298,843,485	(2,318,195)	(8,710,534)	287,814,756	104.66	275,000,000	275,000,000	4.93%	13,552,790	
4.375% Sep	C	8/18/2005	9/1/2017	4.375%	129,500,000	0		129,500,000	(2,460,193)	(2,768,158)	124,271,649	95.96	129,500,000	129,500,000	4.82%	6,242,980	
5.80% Aug	S	8/13/2008	8/1/2018	5.800%	300,000,000	(441,000)		299,559,000	(2,545,629)		297,013,371	99.00	300,000,000	300,000,000	5.93%	17,800,188	
5.125% Jun	S	6/4/2009	6/1/2019	5.125%	400,000,000	(2,160,000)	(632,149)	397,207,851	(3,217,704)		393,990,147	98.50	400,000,000	400,000,000	5.32%	21,282,968	
3.20% Nov	S	11/16/2010	11/15/2020	3.200%	400,000,000	(1,628,000)		398,372,000	(3,187,638)		395,184,362	98.80	400,000,000	400,000,000	3.34%	13,370,600	
6.25% Sept	S	8/15/2007	9/1/2037	6.250%	350,000,000	(2,877,000)	1,693,270	348,816,270	(3,677,728)		345,138,542	98.61	350,000,000	350,000,000	6.35%	22,238,515	
6.50% Aug	S	8/13/2008	8/1/2038	6.500%	300,000,000	(1,206,000)		298,794,000	(3,221,380)		295,572,620	98.52	300,000,000	300,000,000	6.61%	19,840,630	
4.75% Aug	S	8/9/2011	8/15/2041	4.750%	250,000,000	(955,000)		249,045,000	(2,616,391)		246,428,609	98.57	250,000,000	250,000,000	4.84%	12,101,715	
2.25% Sept	S	9/11/2012	9/15/2022	2.250%	300,000,000	(294,000)	(1,785,173)	297,920,828	(2,189,533)	(522,398)	295,208,897	98.40	300,000,000	300,000,000	2.43%	7,292,004	
3.60% Sept	S	9/11/2012	9/15/2042	3.600%	500,000,000	(1,730,000)	(42,926,537)	455,343,463	(4,774,221)		450,569,242	90.11	500,000,000	500,000,000	4.18%	20,906,118	
2.50% Mar	S	3/26/2013	3/15/2023	2.500%	250,000,000	(1,157,000)		248,843,000	(2,132,073)		246,710,927	98.68	250,000,000	250,000,000	2.65%	6,627,464	
3.95% Mar	S	3/26/2013	3/15/2043	3.950%	250,000,000	(1,692,500)		248,307,500	(2,694,573)		245,612,927	98.25	250,000,000	250,000,000	4.05%	10,128,963	
					$3,704,500,000	($16,172,750)	(17,774,853)	3,670,552,397	($35,035,258)	(12,001,090)	$3,623,516,049		$3,704,500,000	$3,704,500,000	4.63%	$171,384,934	
Annual amortization of Reacquired Debt										($22,505,313)						$ 1,163,031	
Annual amortization of Hedging Gain							2,250,064									$ (187,453)	
Cost including loss on reacquired debt																$172,360,512	**4.65%**
Annual amortization of Up Front Fees for Multi-year credit facility (1)																$683,406	
																$173,043,917	**4.67%**

C First Mortgage Bond delivered to MBIA Insurance Corporation
Refinanced 1993 Adams and Morgan County Bonds
S First Mortgage Bonds
@ Estimated Expenses

1) Up Front Fees asociated with the 5 Year Credit Facility,effective 8/1/12, are amortized over the life of the facility and are incorporated into the long-term debt cost
The unamortized upfront fee balance on the existing multi year credit facility will be amortized over life of the new facility

PUBLIC SERVICE COMPANY OF COLORADO
Cost of Debt for 2015
Capital Employed

Description	Coupon Rate	Issue Date	Maturity Date	Par Value	13 Mo. Amount	Hedges/ Premium	Discount	Expense	Capital Employed	Annual Expense Interest	Hedges	Discount	Expense	Cost of Capital	Capital Cost %
4.375% Sept 1, 2017	4.3750	8/18/2005	9/1/2017	129,500,000	129,500,000	0	-	947,992	128,552,008	5,665,625	0	0	436,763	6,102,388	4.75%
5.80% Aug 1, 2018	5.8000	8/13/2008	8/1/2018	300,000,000	300,000,000	0	136,447	788,704	299,074,848	17,400,000	0	44,221	255,611	17,699,832	5.92%
5.125% Jun 1, 2019	5.1250	6/4/2009	6/1/2019	400,000,000	400,000,000	(247,365)	846,615	1,263,925	397,642,095	20,500,000	63,128	216,059	322,558	21,101,746	5.31%
3.2% Nov 15, 2020	3.2000	11/8/2010	11/15/2020	400,000,000	400,000,000	0	875,175	1,715,824	397,409,001	12,800,000	0	162,711	319,003	13,281,713	3.34%
2.25% Sep 15, 2022	2.2500	9/11/2012	9/15/2022	300,000,000	300,000,000	(1,282,824)	211,673	2,127,204	296,378,299	6,750,000	177,884	29,352	294,970	7,252,206	2.45%
2.50% Mar 1, 2023	2.5000	3/12/2013	3/15/2023	250,000,000	250,000,000	0	894,346	1,651,001	247,454,653	6,250,000	0	116,036	214,208	6,580,244	2.66%
6.25% Sept 1, 2037	6.2500	8/15/2007	9/1/2037	350,000,000	350,000,000	1,248,707	2,122,618	2,711,138	346,414,951	21,875,000	(56,288)	95,682	122,210	22,036,604	6.36%
6.50% Aug 1, 2038	6.5000	8/13/2008	8/1/2038	300,000,000	300,000,000	0	929,015	2,479,616	296,591,369	19,500,000	0	40,218	107,346	19,647,564	6.62%
4.75% Aug 15, 2041	4.7500	8/2/2011	8/15/2041	250,000,000	250,000,000	0	831,072	2,278,850	246,890,078	11,875,000	0	31,793	87,177	11,993,970	4.86%
3.60% Sep 15, 2042	3.6000	9/11/2012	9/15/2042	500,000,000	500,000,000	(38,892,314)	1,568,416	4,691,773	454,847,497	18,000,000	1,428,536	57,609	172,331	19,658,476	4.32%
3.95% Mar 15, 2043	3.9500	3/12/2013	3/15/2043	250,000,000	250,000,000	0	1,564,508	2,492,221	245,943,271	9,875,000	0	56,437	89,903	10,021,340	4.07%
4.30% Mar 15, 2044	4.3000	3/10/2014	3/15/2044	300,000,000	300,000,000	0	1,058,660	2,858,926	296,082,414	12,900,000	0	36,853	99,531	13,036,384	4.40%
5.00% May 1, 2045	5.0000	5/1/2015	5/1/2045	350,000,000	215,384,615	0	-	2,126,746	213,257,869	11,666,667	0	0	78,253	11,744,920	5.51%
Total Debt				4,079,500,000	3,944,884,615	(39,173,797)	11,038,546	28,133,920	3,866,538,353	175,057,292	1,613,260	886,971	2,599,866	180,157,388	4.66%
Amortization of hedging gains or losses associated with refinanced debt (a)									543,198					(1,559,966)	
Amortization of expenses associated with refinanced debt (b)								36,345,818	(8,211,898)					1,142,117	
Fees on 5-year Credit Facility (c)									-					683,406	
Grand Total									3,858,869,653					180,422,944	**4.68%**

(a) Hedging balances and amortization that are no longer attached to outstanding deb
(b) Loss on reacquired debt balances and amortization that are no longer attached to outstanding debt
(c) Credit facility fees that were prepaid and will be amortized through the ending date of 7/27/17

Cost of Long-Term Debt Example: Overview and Prior Yield to Maturity Method

Overview:

This example highlights the differences between the "Capital Employed" methodology used in this current case and the "Yield Method" used in prior cases for the Company's cost of long-term debt calculation. Page 1 shows an example of the previously used Yield method, Page 2 shows the same example using the Capital Employed Method, and Pages 3 through 5 provide additional commentary and graphs showing the income statement impact created by the Yield method. In the example, we are assuming a 5% coupon, ten-year bond is issued at par value ($100) with issuance costs of $2. This results in net proceeds of $98, which is the amount of debt available to finance rate base. For simplicity, this example ignores depreciation by assuming that it would be reinvested to maintain rate base and does not include the equity component of financing.

Yield Methodology:

In previous rate cases, our cost of long-term debt was calculated using a yield-to-maturity formula, which calculates the fixed annual rate that needs to be charged over the life of the bond for the Company to recover its coupon payments and debt issuance costs. While this fixed rate is mathematically correct from a present value perspective, it results in a negative income statement impact in the early years of a bond and a positive income statement impact in the later years of a bond. This is because the fixed debt rate is applied to a rate base balance that is increasing due to the collection of the debt issuance costs from customers (debt issuance costs are amortized over the life of the bond as a non-cash expense). We under-recover our actual costs early in the life of the bond and over recover our actual costs later in the bond's life.

Assumptions: Hypothetical Bond

Issuance Date	1/1/2015	Par Value	$ 100
Maturity Date	1/1/2025	Issuance Expenses	$ 2
Bond Length (years)	10	Cash Received at Issuance (par value less issuance cost)	$ 98
Coupon Rate	5.0%	Bond Yield (Rate charged to customers under Old methodology)	5.26%

Capital Employed (Cash Available to Finance Rate Base)	**Year 0**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**
Par Value of Bond	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00
Issuance Expense Balance	$ (2.00)	$ (1.80)	$ (1.60)	$ (1.40)	$ (1.20)	$ (1.00)	$ (0.80)	$ (0.60)	$ (0.40)	$ (0.20)	$ (0.00)
Capital Employed - Ending Balance (Rate Base)	$ 98.00	$ 98.20	$ 98.40	$ 98.60	$ 98.80	$ 99.00	$ 99.20	$ 99.40	$ 99.60	$ 99.80	$ 100.00
Capital Employed - Average Balance (Rate Base)		$ 98.10	$ 98.30	$ 98.50	$ 98.70	$ 98.90	$ 99.10	$ 99.30	$ 99.50	$ 99.70	$ 99.90

Debt Costs	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**
Interest Expense (Coupon Payment)	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0
Amortization of Issuance Expense	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20
Total Annual Debt Expense ($)	$ 5.20	$ 5.20	$ 5.20	$ 5.20	$ 5.20	$ 5.20	$ 5.20	$ 5.20	$ 5.20	$ 5.20
Annual Cost of Debt (Yield calculation - constant over bond life)	**5.26%**	**5.26%**	**5.26%**	**5.26%**	**5.26%**	**5.26%**	**5.26%**	**5.26%**	**5.26%**	**5.26%**

Company Income Statement	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**
Revenue (annual cost of debt x average rate base)	**$ 5.16**	**$ 5.17**	**$ 5.18**	**$ 5.19**	**$ 5.20**	**$ 5.21**	**$ 5.22**	**$ 5.23**	**$ 5.24**	**$ 5.25**
Interest Expense	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00
Amortization of Issuance Expense	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20
Pre-tax Income	$ (0.04)	$ (0.03)	$ (0.02)	$ (0.01)	$ 0.00	$ 0.01	$ 0.02	$ 0.03	$ 0.04	$ 0.05
Income Tax	$ (0.02)	$ (0.01)	$ (0.01)	$ (0.00)	$ 0.00	$ 0.00	$ 0.01	$ 0.01	$ 0.02	$ 0.02
Net Income	**$ (0.02)**	**$ (0.02)**	**$ (0.01)**	**$ (0.01)**	**$ 0.00**	**$ 0.01**	**$ 0.01**	**$ 0.02**	**$ 0.03**	**$ 0.03**

Cost of Long-Term Debt Example: Proposed Capital Employed Method

Capital Employed Methodology

The Capital Employed method calculates the test year debt cost based on the net cash that is available from our bonds during the test year. At the time of issuance, underwriting, discount, and other expenses reduce the cash that we receive from our long-term debt offerings. We collect these issuance costs from customers over the life of the bond as the costs are amortized, which increases the cash available from the bond to finance rate base. The capital employed method focuses on this increasing level of cash to calculate the effective interest rate for the test year. This is an improvement over the previous cost of debt calculation for two reasons: it is a more accurate representation of the actual debt financing costs for the test year and it eliminates the income statement impact that was created by the previous method. This method is also used in the Minnesota jurisdiction.

Assumptions: Hypothetical Bond

Issuance Date	1/1/2015	Par Value	$ 100
Maturity Date	1/1/2025	Issuance Expenses	$ 2
Bond Length (years)	10	Cash Received at Issuance (par value less issuance cost)	$ 98
Coupon Rate	5.0%		

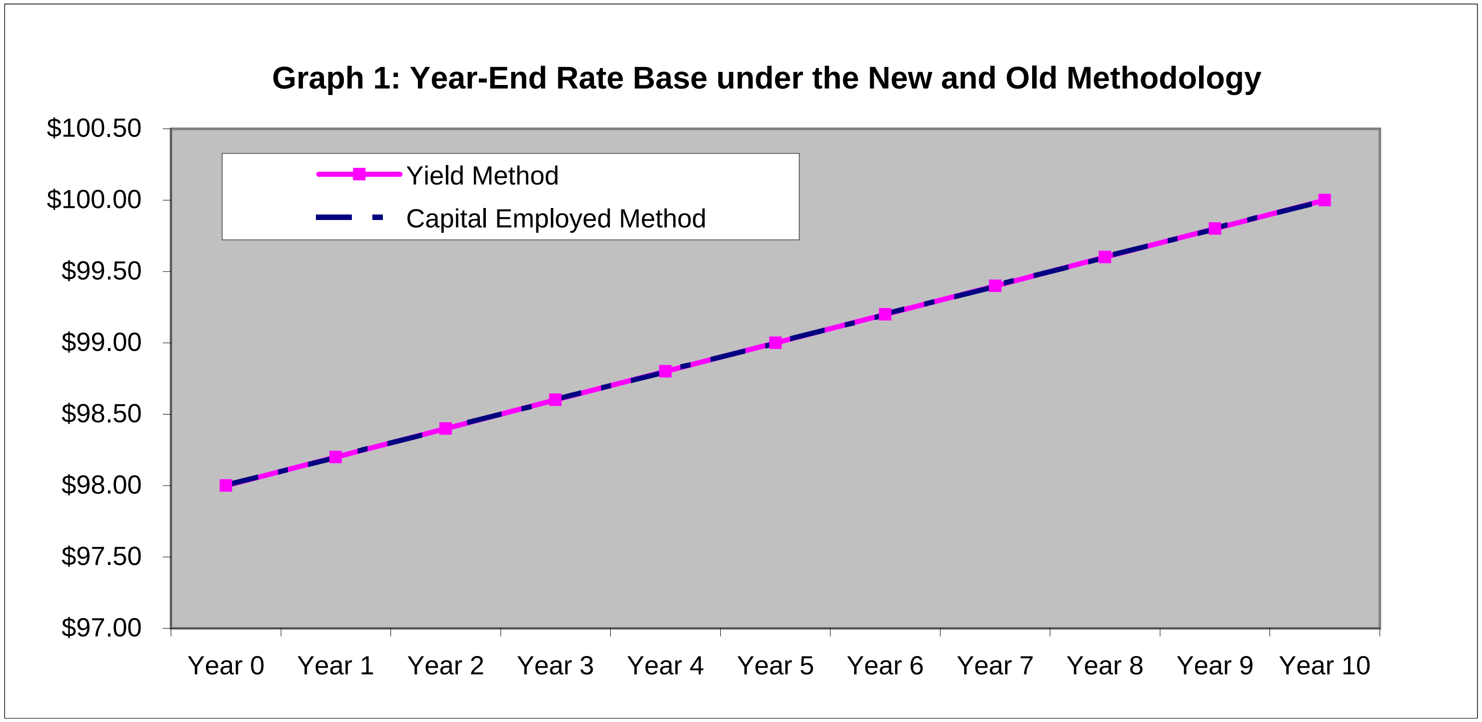
Capital Employed (Cash Available to Finance Rate Base)	**Year 0**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**
Par Value of Bond	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00
Issuance Expense Balance	$ (2.00)	$ (1.80)	$ (1.60)	$ (1.40)	$ (1.20)	$ (1.00)	$ (0.80)	$ (0.60)	$ (0.40)	$ (0.20)	$ (0.00)
Capital Employed - Ending Balance (Rate Base)	$ 98.00	$ 98.20	$ 98.40	$ 98.60	$ 98.80	$ 99.00	$ 99.20	$ 99.40	$ 99.60	$ 99.80	$ 100.00
Capital Employed - Average Balance (Rate Base)		$ 98.10	$ 98.30	$ 98.50	$ 98.70	$ 98.90	$ 99.10	$ 99.30	$ 99.50	$ 99.70	$ 99.90

Debt Costs	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**
Interest Expense (Coupon Payment)	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0
Amortization of Issuance Expense	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20
Total Annual Debt Expense ($)	$ 5.20	$ 5.20	$ 5.20	$ 5.20	$ 5.20	$ 5.20	$ 5.20	$ 5.20	$ 5.20	$ 5.20
Annual Cost of Debt (Total Annual Debt Expense/Capital Employed)	**5.30%**	**5.29%**	**5.28%**	**5.27%**	**5.26%**	**5.25%**	**5.24%**	**5.23%**	**5.22%**	**5.21%**

Company Income Statement	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**
Revenue (annual cost of debt x average rate base)	**$ 5.20**	**$ 5.20**	**$ 5.20**	**$ 5.20**	**$ 5.20**	**$ 5.20**	**$ 5.20**	**$ 5.20**	**$ 5.20**	**$ 5.20**
Interest Expense	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0	$ 5.0
Amortization of Issuance Expense	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20
Pre-tax Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Income Tax	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Income	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

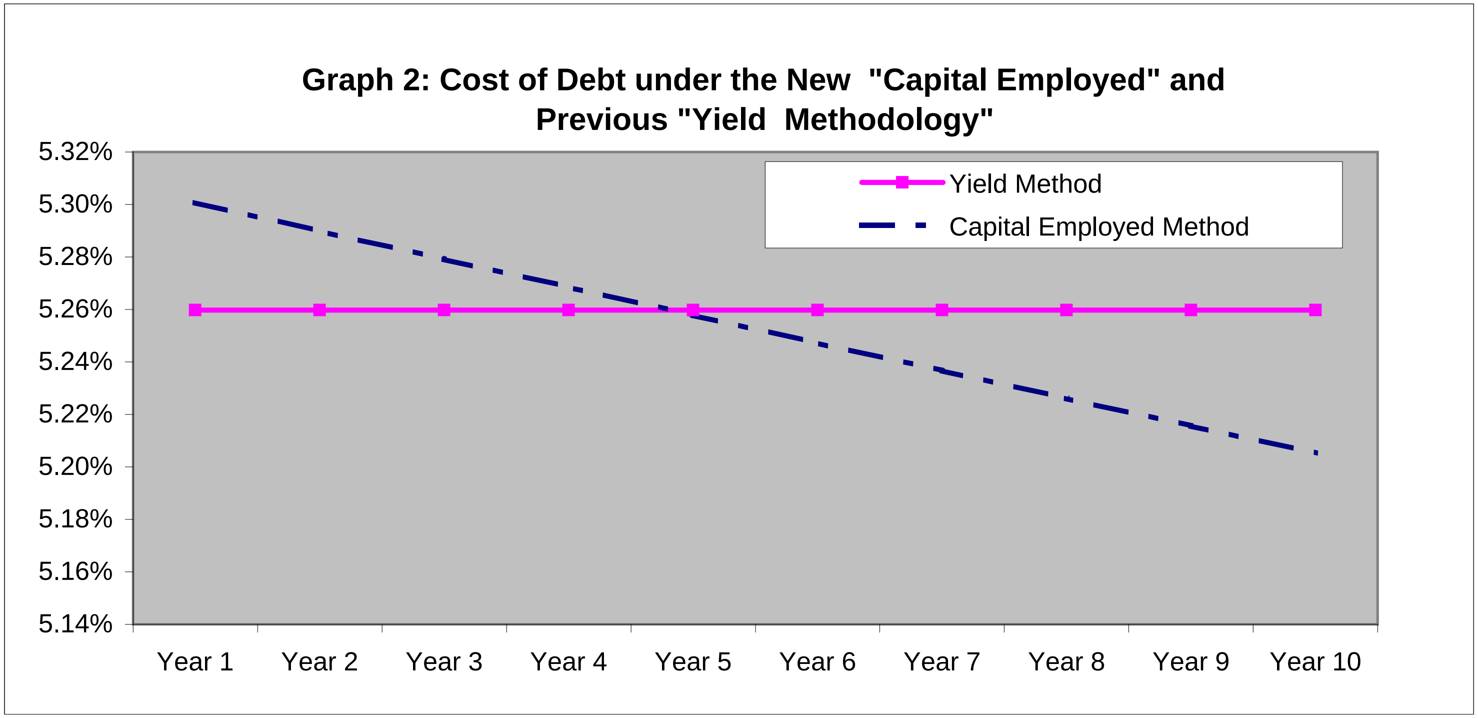
Cost of Long-Term Debt Example: Graph of Rate Base

Graph 1 depicts the rate base financed with the bond proceeds (depreciation is assumed to be reinvested so it is ignored). The rate base increases each year since it is assumed the $0.20 per year of amortized issuance costs is reinvested (the debt issuance amortization is a non-cash expense). This is an important point when coupled with Graphs 2 and 3.



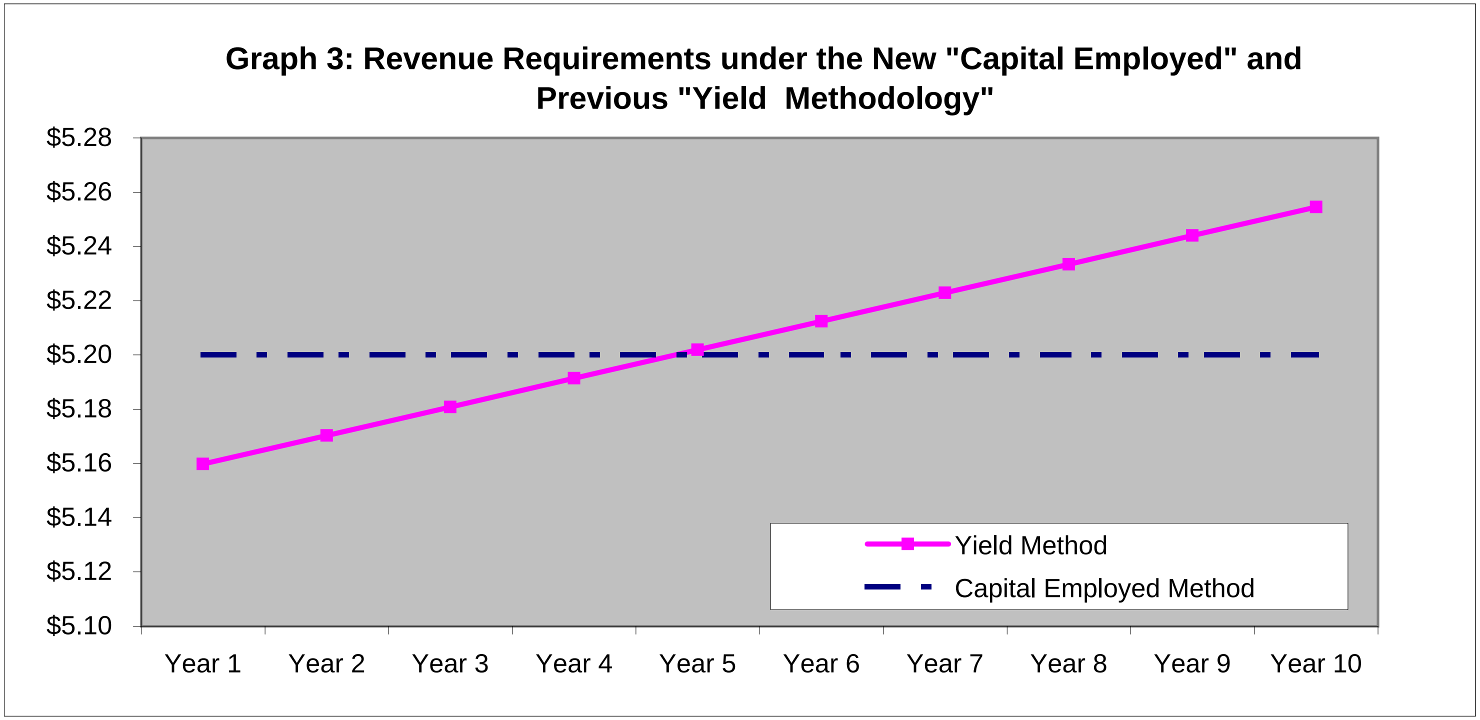
Cost of Long-Term Debt Example: Graph of Debt Cost under each Methodology

Graph 2 illustrates the annual cost of long-term debt under each methodology. Under the yield method, the cost of debt is constant for the life of the bond. Comparatively, the cost of debt under the capital employed method changes on an annual basis since the denominator (cash available to finance rate base) used to calculate the effective annual rate increases each year due to the cash received for the issuance expense amortization. This calculation is shown on page 2 of the exhibit.



Cost of Long-Term Debt Example: Graph of Revenue Requirement under Each Methodology

Graph 3 shows the end result of the two methods in the form of the annual revenue requirement that would be charged to customers. Under the capital employed method, customers will be charged a constant amount over the life of the bond while customers would be charged an increasing amount under the yield method. The increasing revenue under the yield/previous method results in the income statement impact. The Company records the same amount of interest expense (including issuance amortization) each year over the life of the bond yet does not collect the same amount of revenue from customers each year. The income statement impact of the yield method is shown on Page 1 of the exhibit. The capital employed method addresses this issue, is more reflective of test-year ratemaking principles since it accurately reflects the costs of the test period, and also reduces the inequities resulting from a changing revenue requirement.



PSCo Credit Metrics - GAAP (Capital Employed Methodology)
Dollars in Millions
May 19, 2014

NOTE: PPA CONTRACTS ARE BASED ON PRELIMINARY INPUTS INTO THE PRODUCTION BUDGET; FINAL BUDGET WILL BE AVAILABLE IN JUNE 2014

Adjusted FFO Calculation [1]	Year End 2013	Projected Year End[4] 2014	Projected Year End[4] 2015
Adjusted Funds from Operations	**$ 1,154.6**	**$ 927.4**	**$ 999.5**
Interest Charges and Financing Costs [1]	$ 160.9	$ 148.6	$ 165.9
Plus: AFUDC-Debt	$ 12.7	$ 18.3	$ 14.5
Plus: Imputed Interest Operating Leases [2]	$ 5.1	$ 4.4	$ 3.8
Plus: Imputed Interest for PPAs [3]	$ 17.6	$ 16.8	$ 15.1
Adjusted Interest Expense	**$ 196.3**	**$ 188.1**	**$ 199.2**
Operating Income	$ 828.8	$ 811.1	$ 924.5
Plus: Depreciation & Amortization	$ 370.5	$ 379.1	$ 397.6
EBITDA	**$ 1,199.3**	**$ 1,190.2**	**$ 1,322.2**
Plus: Implied Depreciation Adjustment for PPAs [3]	$ 32.4	$ 33.3	$ 28.0
Plus: Imputed Interest for Operating Leases[2]	$ 5.1	$ 4.4	$ 3.8
Plus: Imputed Interest for PPAs[3]	$ 17.6	$ 16.8	$ 15.1
Adjusted EBITDA	**$ 1,254.4**	**$ 1,244.6**	**$ 1,369.0**
Short-Term Debt	$ -	$ 440.5	$ 392.0
Long-Term Debt (Includes Current Portion)	$ 3,690.0	$ 3,714.6	$ 4,064.1
Capital Leases	$ 182.7	$ 175.9	$ 168.3
Total Balance Sheet Debt	$ 3,872.6	$ 4,331.0	$ 4,624.5
Off-Balance Sheet Debt for Operating Leases [2]	$ 97.7	$ 83.6	$ 72.1
Off-Balance Sheet Debt for PPAs [3]	$ 338.5	$ 306.1	$ 272.0
Adjusted Total Debt	**$ 4,308.8**	**$ 4,720.8**	**$ 4,968.6**
Common Equity from Balance Sheet	$ 4,802.0	$ 4,881.0	$ 5,034.0

Adjusted Ratios: S&P Methodology

	2013	2014	2015
FFO/Interest (x)	6.9	5.9	6.0
Debt/EBITDA (x)	3.4	3.6	3.5
FFO/Debt (%)	27.1	20.5	20.6
Total Debt/Total Capital (%)	47.3	49.2	49.7
Total Equity/Total Capital (%)	52.7	50.8	50.3

Unadjusted Ratios

	2013	2014	2015
FFO/Interest	7.4	6.3	6.3
Debt/EBITDA (x)	3.2	3.4	3.4
FFO/Debt (%)	29.1	21.5	21.5
Total Debt/Total Capital (%)	44.6	47.0	47.9
Total Equity/Total Capital (%)	55.4	53.0	52.1

Credit Metric Benchmarks

S&P Benchmarks			
Financial Risk	**Debt/Capital (%)**	**FFO/Debt (%)**	**Debt/EBITDA (%)**
Minimal	less than 25	greater than 60	less than 1.5
Modest	25-35	45-60	1.5-2
Intermediate	35-45	30-45	2-3
Significant	45-50	20-30	3-4
Aggressive	50-60	12-20	4-5
Highly Leverage	greater than 60	less than 12	greater than 5

Business Risk	**Financial Risk Profile**					
	Minimal	**Modest**	**Intermediate**	**Significant**	**Aggressive**	**Highly Leveraged**
Excellent	AAA	AA	A	A-	BBB	-
Strong	AAA	AA	A-	BBB	BBB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	-	BBB-	BB+	BB	BB-	B
Weak	-	-	BB	BB-	B+	B-
Vulnerable	-	-	-	B+	B	CCC+

Moody's Credit Metric Benchmarks									
Ratio	**Aaa**	**Aa**		**A**		**Baa**		**Ba**	
FFO/Interest (x)	> 8.0	8.0	6.0	6.0	4.5	4.5	2.7	2.7	1.5