Direct Testimony and Schedules

Paul A. Johnson

Before the Minnesota Public Utilities Commission

State of Minnesota

In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-21-630

Exhibit___(PAJ-1)

Capital Structure, Overall Rate of Return And Investor Relations

October 25, 2021

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Paul A. Johnson. I am Vice President, Treasurer and Investor Relations of Xcel Energy Services, Inc., the service company subsidiary of Xcel Energy Inc. (Xcel Energy or XEI).

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

A. I am testifying on behalf of Northern States Power Company (NSPM or the Company), d/b/a Xcel Energy.

Q. PLEASE BRIEFLY OUTLINE YOUR RESPONSIBILITIES AS VICE PRESIDENT, TREASURER AND INVESTOR RELATIONS.

A. As Vice President, Treasurer and Investor Relations, I am responsible for recommending and implementing the financing required to achieve target capital structure objectives at each of the regulated utility operating companies and at Xcel Energy. I am also responsible for corporate cash forecasting and management, pension plan management, hazard risk insurance, treasury services, and financial policies. In addition, I am responsible for developing and maintaining relationships with investors, investor analysts, and internal and external stakeholders to ensure that they are well positioned to make financial or investment decisions. I am also responsible for working with the credit rating agencies and providing timely updates as required. A description of my qualifications, duties, and responsibilities is included in this testimony as Exhibit __(PAJ-1), Schedule 1.

Q. PLEASE STATE THE PURPOSE OF YOUR TESTIMONY.

A. In my testimony, I discuss a number of topics related to the Company's cost of capital. In particular, I:

- Discuss financial integrity, its importance to NSPM and its stakeholders, and the need for NSPM to demonstrate stable overall financial health in order to access capital at attractive terms in varied economic conditions and raise debt capital for utility investments at low costs;
- Discuss the criteria the ratings agencies use to measure financial integrity;
- Provide a current assessment of NSPM's financial integrity and describe the impact that regulatory decisions, changes in cash flow and the timely recovery of prudent utility costs have on NSPM's financial integrity;
- Present and support the capital structure and overall cost of capital proposed by NSPM for the term of the Multi-Year Rate Plan (MYRP), 2022-2024; and
- Discuss the importance of the Company's Investor Relations efforts.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I present my testimony in the following sections:

- Section II provides a Summary and Overview of NSPM's proposed Capital Structure, Cost of Debt, and Rate of Return (ROR) for the time period covered by this rate case.
- Section III identifies the Commission's standards for review of capital structure and explains the purpose of, and how the Company determines, the capital structure.
- Section IV describes the Company's historical and planned financing and investment activities, explains the importance of the regulatory environment to the credit rating agencies' and investors' perceptions of

the regulatory risk and to the Company's ability to carry out its capital expenditure plans. This section also includes a discussion of the credit rating agencies' criteria and NSPM's current credit ratings and financial metrics.

- Section V provides a detailed description of the components of NSPM's capital structure and costs of long-term debt (LTD) and short-term debt (STD) for 2022 through 2024.
- Section VI discusses the need for and importance of the Company's Investor Relations expenses.
- Section VII includes a Conclusion and Recommendations.

II. SUMMARY AND OVERVIEW

Q. WHAT DO YOU DISCUSS IN THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section, I provide an overview of NSPM's recommended capital structure for 2022 through 2024.

Q. PLEASE SUMMARIZE NSPM'S PROPOSED CAPITAL STRUCTURE, COSTS OF DEBT AND EQUITY, AND ROR FOR 2022, 2023 AND 2024.

A. NSPM's recommended capital structure for the 2022 test year, including costs of STD, LTD, and Common Equity, is included on Exhibit___(PAJ-1), Schedule 2, Page 1 of 3, and is summarized below. This recommended capital structure, and the capital structures recommended for plan years 2023 and 2024, will allow NSPM to continue to raise capital at competitive pricing in order to keep costs low for customers, will support the credit ratings guidance provided by the three recognized credit rating agencies and will help maintain NSPM's financial integrity, which I discuss further in Section IV.

Table 1

2022 Test Year

Recommended Capital Structure Ratios and Costs

	Percent of Total Capital	Cost	Weighted Cost
STD	0.61%	0.94%	0.01%
LTD	46.89%	4.13%	1.94%
Common Equity	52.50%	10.20%	5.36%
Total Capital	100.00%		7.31%

NSPM's proposed capital structure for the 2023 plan year is included on Exhibit___(PAJ-1), Schedule 2, Page 2 of 3, and can be summarized as follows:

Table 2

2023

Recommended Capital Structure Ratios and Costs

	Percent of Total Capital	Cost	Weighted Cost
STD	1.00%	0.80%	0.01%
LTD	46.50%	4.12%	1.91%
Common Equity	52.50%	10.20%	5.36%
Total Capital	100.00%		7.28%

The Company's proposed capital structure for the 2024 plan year is included on Exhibit___(PAJ-1), Schedule 2, Page 3 of 3, and can be summarized as follows:

Table 3

2024

Recommended Capital Structure Ratios and Costs

	Percent of Total Capital	Cost	Weighted Cost
STD	0.42%	1.47%	0.01%
LTD	47.08%	4.09%	1.93%
Common Equity	52.50%	10.20%	5.36%
Total Capital	100.00%		7.30%

Q. HOW DOES THE USE OF A 52.50 PERCENT EQUITY RATIO IN EACH OF THE YEARS OF NSPM'S MYRP COMPARE TO RECENTLY AUTHORIZED CAPITAL STRUCTURES FOR NSPM?

A. NSPM's recommended capital structure of 52.50 percent equity for the 2022 test year and for the 2023 and 2024 plan years remains unchanged from the 52.50 percent equity ratio authorized by the Commission in rate cases dating back to 2013, and is consistent with authorized capital structures going even farther back in time. NSPM's authorized equity ratio has ranged between 52.47 percent and 52.56 percent over the last several electric general rate case proceedings dating back to 2009. In each of those cases, the Commission agreed with the reasonableness of NSPM's proposed capital structure. Throughout this time, NSPM has been consistent and transparent in managing its capital structure consistent with the Commission's authorized capital structure and to ensure NSPM's financial integrity. NSPM is following those same principles in this proceeding.

Q. DO YOU BELIEVE THE RECOMMENDED RORS RESULTING FROM YOUR PROPOSED CAPITAL STRUCTURES ARE REASONABLE AND APPROPRIATE?

A. Yes. NSPM's recommended RORs for 2022 through 2024 are reasonable, as discussed in Mr. D'Ascendis direct testimony, and reflect a decrease from the cost of LTD and STD used in the Commission-approved Settlement of the Company's 2015 rate case.

The projected cost of LTD for 2022 through 2024 ranges from 4.09 to 4.13 percent, as compared to 4.75 to 4.81 percent authorized in our last rate case. The projected cost of STD for 2022 through 2024 ranges from 0.80 to 1.47 percent, as compared to 1.84 to 4.81 percent authorized in the last rate case. It should be noted that, while the cost of debt has decreased, it is due to the current low interest rate environment and NSPM's credit profile. The recommended Return on Equity (ROE) of 10.20 percent is supported in the Direct Testimony of Company Witness Mr. Dylan D'Ascendis.

III. STANDARDS AND FUNDAMENTAL CONSIDERATIONS FOR THE NSPM CAPITAL STRUCTURE

Q. PLEASE SUMMARIZE THE MOST SIGNIFICANT POINTS YOU DISCUSS IN THIS SECTION OF YOUR DIRECT TESTIMONY.

A. I discuss the following points:

- The basic regulatory standard for reviewing a utility's capital structure is one of reasonableness.
- NSPM's capital structure satisfies the Commission's reasonableness criteria, and provides long-term customer benefits, including access to capital markets at favorable terms to finance capital expenditures. That, in turn, allows NSPM to serve its customers safely and reliably and to invest in carbon-free renewable generation to meet Minnesota energy

policy and societal goals and customer expectations and to do so at a competitive cost.

- NSPM's management of its capital structure is based on long-term considerations, including the Commission's authorized capital structure, credit ratings, future financing plans, the relative capital structures of other utilities, and overall financial market conditions.

Q. WHAT STANDARD HAS THE COMMISSION USED TO EVALUATE CAPITAL STRUCTURES FOR SETTING UTILITY RATES?

A. The Commission has used a reasonableness standard in making capital structure decisions. To determine whether a company's actual capital structure is reasonable, the Commission has considered:

- How the debt and equity ratios for the utility compare to similar utility companies;
- Whether the utility's capital structure is an actual capital structure based on market forces, or is an internal accounting capital structure;
- Whether the capital structure supports long-term credit quality given the utility's capital investment forecast, future financing requirements, and the need to access public capital markets; and
- Whether the capital structure provides long-term cost benefits to customers.

Q. DOES NSPM'S PROPOSED CAPITAL STRUCTURE MEET THE COMMISSION'S STANDARDS AND CRITERIA FOR REASONABLENESS?

A. Yes. NSPM's proposed capital structure meets the Commission's standards and criteria. NSPM's capital structure is within a reasonable range of equity ratios for the Utility Proxy Group, as Mr. D'Ascendis's analysis shows. Further, NSPM's proposed capital structure is an actual, market-based capital structure and is comparable to its historical capital structure and consistent with the Commission's last authorized capital structure. NSPM's historical capital structure has provided long-term benefits to customers by providing reasonable costs of capital and sufficient access to capital markets in a wide range of market conditions to finance capital investments. Finally, the Commission has consistently found NSPM's recommended capital structures to be reasonable and the requested equity ratio in this case is identical to the equity ratio approved in Docket No. E002/GR-13-868 and utilized in the Settlement of the 2015 rate case, and is in line with the approved equity ratio in the three cases prior to those proceedings (Docket Nos. E002/GR-12-961, E002/GR-10-971, and E002/GR-08-1065).

Q. HOW DOES NSPM'S 52.50 PERCENT EQUITY RATIO COMPARE WITH THE EQUITY RATIOS OF MR. D'ASCENDIS'S UTILITY PROXY GROUP?

A. NSPM's 52.50 equity ratio is well within the range of equity ratios maintained by Mr. D'Ascendis's Utility Proxy Group. As shown on page 2 of Exhibit___(DWD-1), Schedule 3, common equity ratios of the utilities range from 31.06 percent to 56.14 percent for fiscal year 2020. Taking this a step further, the equity ratios maintained by the operating subsidiaries of Mr. D'Ascendis's Utility Proxy Group ranged from 41.41% to 54.98% for fiscal year 2020.[1]

No matter what range is analyzed, NSPM's requested equity ratio of 52.50% falls within the range and therefore, should be considered reasonable for rate making purposes.

[1] Exhibit DWD-1, Schedule 3, Page 3.

Q. WHEN YOU DESCRIBE NSPM'S CAPITAL STRUCTURE AS AN ACTUAL AND MARKET-BASED CAPITAL STRUCTURE, WHAT DOES THAT MEAN?

A. NSPM is a separate, stand-alone legal Minnesota corporation that manages its own separate capital structure consistent with the regulatory and financial risk prevailing at the operating company level and within its respective jurisdictions. Moody's, Fitch and Standard and Poor's (S&P) all assign credit ratings to NSPM as a corporate entity and to each one of its individual bond issuances. NSPM files its own quarterly and annual financial statements with the Securities and Exchange Commission (SEC), which credit rating agencies and investors use to analyze the company. In addition, debt to support capital expenditures and operations of NSPM is issued specifically by the NSPM legal entity.

It is important to note that although the Commission may view the Electric and Gas Departments as different entities, from a financial statement perspective, these are both under the umbrella of one company.

Q. WHAT FACTORS ARE CONSIDERED IN PLANNING AND MANAGING THE CAPITAL STRUCTURE FOR NSPM?

A. NSPM considers a number of factors, including:

- Credit rating evaluations that reflect rating agency assessments of NSPM's business and financial risk;
- NSPM's long-term construction cycle and the scale of its capital investments;
- Capital structures of other vertically-integrated, regulated utilities;
- The long-term stability of the capital structure being appropriately matched with the long lives of the NSPM's asset investments;
- The current macroeconomic outlook and associated risk factors affecting

the utility sector and capital markets generally;

- The need to manage the maturities of LTD to avoid excessive refinancing risk in any given year; and
- The Commission's authorized capital structure.

Q. DO YOU HAVE A TARGET FOR MANAGING NSPM'S EQUITY RATIO?

A. Yes. NSPM continues to target a regulated capital structure having an equity ratio of 52.50 percent, which supports NSPM's current credit ratings and projected cost of long-term and short-term debt, as well as providing continued access to capital markets in varying market conditions and at an attractive cost of capital.

Q. WHY IS THAT TARGET EQUITY RATIO APPROPRIATE?

A. The 52.50 percent target equity ratio has long-supported NSPM's current S&P A- and Moody's A2 corporate credit ratings, and NSPM aims to continue to maintain these ratings. NSPM believes that its current corporate credit ratings provide access to financing at a low cost, especially while making significant capital investments to provide safe and reliable service to customers and support the clean energy transition that enable shared carbon reduction goals. As discussed earlier, the target regulated equity ratio of 52.50 percent is also consistent with other utility capital structures, as shown by the equity ratios of Mr. D'Ascendis's Utility Proxy Group.

Q. HOW DO CUSTOMERS BENEFIT FROM NSPM'S CAPITAL STRUCTURE AND EQUITY RATIO?

A. NSPM's capital structure and equity ratio have a significant effect on its financial integrity. NSPM's financial integrity is essential to: (i) its ability to finance its investments and operations at a competitive cost in all market conditions; and (ii) maintain its credit ratings. NSPM's capital structure has allowed it to simultaneously finance its ongoing investments and maintain access to capital at competitive rates while also maintaining its credit ratings. NSPM's S&P, Moody's and Fitch's corporate credit ratings and credit outlook have remained stable for over a decade. In addition, NSPM has maintained its financial strength to ensure consistent access to capital markets under a range of economic conditions and raise the capital required to efficiently fund its future investments, such as its investments in renewable energy. Finally, the lower proposed cost of debt in this proceeding, made possible in part by the Company's credit ratings, compared to that authorized in the Company's last rate case, provides a tangible benefit to our customers.

Q. WHAT DOES THE TERM "FINANCIAL INTEGRITY" MEAN?

A. Financial integrity refers to a company's financial strength and its ability to attract capital in varying economic conditions. The ability to attract capital at a competitive cost in various economic conditions is integral to a utility's obligation to provide safe, reliable and affordable utility service to customers. Financial integrity ensures that the utility will have the flexibility to withstand unanticipated macroeconomic events outside of its control, such as the 2008-2009 financial crisis or more recently, the COVID-19 pandemic.

Q. WHAT FACTORS CONTRIBUTE TO A UTILITY'S FINANCIAL INTEGRITY?

A. The financial integrity of a regulated utility is largely a function of its capital structure, ROE, and cash flow, but can be impacted by other factors as well. To maintain a strong financial profile, a utility needs to have the opportunity to recover all prudently-incurred utility costs in a timely manner, which includes not only the costs for capital investments and operations and maintenance expense, but also the costs of servicing debt and providing a fair return for equity investors. This is why constructive and consistent regulatory decisions on capital structure, ROE and the recovery of prudent utility costs are vitally important to NSPM.

IV. NSPM'S CAPITAL EXPENDITURE PLAN, CREDIT RATINGS AND THE REGULATORY ENVIRONMENT

Q. PLEASE SUMMARIZE THE KEY POINTS YOU DISCUSS IN THIS SECTION OF YOUR DIRECT TESTIMONY.

A. The key points are as follows:

- NSPM's capital expenditure program has resulted in corresponding issuances of debt by NSPM as well as equity infusions from Xcel Energy.
- NSPM expects to continue to make significant capital investments in Minnesota, which requires future access to capital at favorable rates.
- Constructive and balanced regulatory decisions are very important to both debt and equity investors, rating agencies, and financial analysts.
- NSPM's credit ratings remain strong, but are dependent on NSPM's business and financial risk, which can be impacted by both favorable and unfavorable regulatory decisions.

A. NSPM Capital Expenditures and Financial Implications

Q. PLEASE SUMMARIZE THE HISTORICAL CONTEXT FOR NSPM'S CAPITAL EXPENDITURES PROGRAM.

A. NSPM has engaged in a large-scale capital expenditure program for necessary investments in its system as well as investment in carbon-free renewable generation to meet Minnesota energy policy and societal goals and customer expectations. As shown on Exhibit___(PAJ-1), Schedule 3, during the period 2011 through 2020, NSPM made capital expenditures of approximately $13.2 billion in its combined gas and electric utility business. As examples, NSPM's investments in wind generation and new transmission projects required significant capital investment during this period. In addition, NSPM has been making ongoing investments to modernize and support its distribution and transmission infrastructure, as discussed by Company witnesses Ms. Kelly Bloch and Mr. Ian Benson.

These and other ongoing investments make it critical that NSPM maintain a strong financial position, so that it can access the capital markets at competitive rates. Investors and credit rating agencies are very focused on Commission decisions on equity ratio, ROE and cost recovery. These decisions can have a significant impact on investor and credit rate agency perceptions, which will impact future cost of capital.

Q. HOW DO FORECAST CAPITAL EXPENDITURE LEVELS COMPARE TO PRIOR YEARS?

A. Exhibit___(PAJ-1), Schedule 3 shows that NSPM's forecasted capital expenditures for 2021 through 2024 are approximately $8.3 billion (91 percent of which is for the electric operations) or an average of approximately $2.1 billion ($1.9 billion for electric) per year. This level of forecasted capital expenditures is higher than the historical average during 2016 through 2020 due to the projects noted earlier. As discussed by Company witnesses Mr. Gregory Chamberlain and Mr. Randy Capra, the Company plans to make significant investments in wind and solar resources over the term of the MYRP as it continues to transition its generation fleet to carbon-free resources.

Q. HOW DOES NSPM'S CAPITAL EXPENDITURE FORECAST AFFECT FINANCING PLANS AND INVESTOR EXPECTATIONS?

A. To fund its forecasted capital expenditures, NSPM will need to access the capital markets in each year 2022 through 2024. It is therefore important for NSPM to meet investor expectations and maintain its current credit ratings to continue to be able to obtain financing at competitive rates. To do so, it is important that NSPM receives timely recovery of the costs of its investments and operations and a reasonable overall cost of capital.

Q. HAS NSPM RECENTLY ISSUED LTD, AND WILL NSPM NEED TO ISSUE LTD IN THE 2022 TO 2024 TIME PERIOD?

A. Yes. NSPM issued a $850 million "Green" First Mortgage Bond on March 30, 2021. NSPM is projected to issue debt in each of the years 2022 through 2024. The precise size, timing and tenor of debt issuances will depend on prevailing financial market conditions and trends at the time of issuance. The forecast included in Schedules 4, 5 and 6 reflect the most recent forecast information available.

Q. WHAT IS A "GREEN" FIRST MORTGAGE BOND?

A. Green bonds are a type of fixed-income instrument that is earmarked to raise funds for climate and environmental related projects. In NSPM's case, the green bonds issued to date (one each in 2019, 2020 and 2021) have been tied to financing investments in wind projects.

Q. DO NSPM'S CUSTOMERS BENEFIT FROM GREEN BONDS?

A. Yes. The main benefit of issuing green bonds is to diversify NSPM's investor base by attracting environmentally focused investors, which are becoming increasingly more common. A larger pool of investors leads to increased investor demand during a bond issuance, which in turn adds pressure on investors to accept a lower return on the debt, lowering our overall cost of LTD paid by Minnesota customers. Simply, by expanding our customer pool for our debt, green bonds can lower our financing costs, thereby lowering our cost of service.

Additionally, Minnesota customers have called for increased renewable energy, and Xcel Energy continues to strive to deliver carbon-free options reliably and at a reasonable cost to our customers, as discussed further by Company witness Mr. Gregory Chamberlain. These green bonds bring global attention to the advances Minnesota has made in implementing wind energy into our grid.

Q. IS THERE EMPIRICAL DATA TO SUPPORT YOUR CLAIM THAT NSPM'S CUSTOMERS BENEFIT FROM ISSUING GREEN BONDS?

A. Yes. In 2019, NSPM issued $600 million in green bonds with an interest rate, or "coupon," of 2.90 percent, setting the record for the lowest coupon on 30-year bonds in utility industry history at the time of the issuance. In 2020, NSPM broke its own record with its issuance of $700 million in green bonds with a coupon of 2.60 percent. Again, NSPM set a new record with the lowest coupon on 30-year bonds in utility industry history at the time of issuance.

Additionally, in the secondary trading markets (i.e., after the bond is originally placed), green bonds have been shown to trade at tighter levels than standard or non-green first mortgage bonds. For example, as of September 2021, green bonds issued by NSPM were trading at tighter credit spreads (or the amount added to prevailing U.S. Treasury rates to determine the overall coupon) than its standard first mortgage bonds.

Trading at tighter levels in the secondary market demonstrates the ever-increasing appetite that fixed-income investors have for green bonds in today's market – a trend that is expected to continue to grow.

Q. WHAT ARE NSPM'S OBJECTIVES WHEN ISSUING LTD?

A. The primary objectives of NSPM's debt financing strategy are to minimize debt costs and exposure to potential adverse market conditions in the future, maximize financing flexibility, maintain a strong liquidity profile and maintain a strong investment grade credit rating.

Q. WHY DOES MAINTAINING FINANCIAL INTEGRITY BENEFIT NSPM'S CUSTOMERS?

A. Financial integrity directly affects both NSPM's ability to access capital to invest in infrastructure necessary to continue to provide safe and reliable utility service as well as its cost of that capital, which is ultimately included in NSPM's customer rates. Attracting competitively priced capital in varying market conditions, including unexpected macroeconomic events outside the Company's control, such as the COVID-19 pandemic, is also critical to maintaining the ability to invest in the infrastructure necessary for NSPM to provide safe and reliable utility service to its customers.

It is important to note, however, that the question of a utility's financial integrity is not necessarily binary (i.e., does a utility have financial integrity or not); rather, the degree of financial integrity and therefore, the cost of capital available to a utility, lies on a spectrum. Weaker financial integrity at a utility increases the issued cost of debt and the implied cost of equity, which increases the overall weighted average cost of capital (WACC) and the ultimate financing costs paid by customers. Strong financial integrity has the opposite effect, which in turn provides a direct benefit to customers. Financial integrity and strong credit ratings become even more important when the capital markets are in distress and access to capital and liquidity can be critical.

B. Importance of Credit Ratings and a Healthy Regulatory Environment

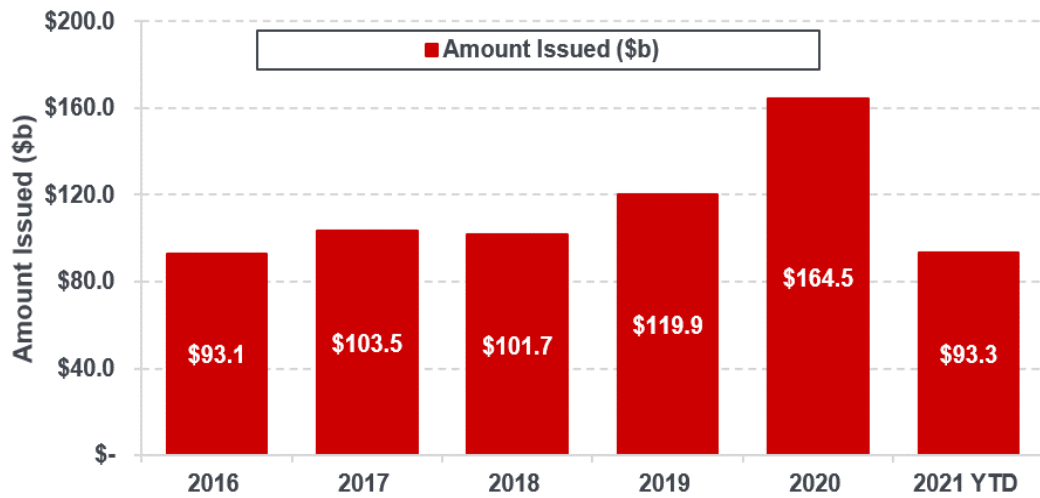
Q. CAN YOU EXPLAIN CREDIT RATINGS IN MORE DETAIL?

A. Yes. A credit rating measures credit risk, which is the ability and willingness of an issuer to fulfill its financial obligations in full and on time. Credit ratings help debt investors differentiate between companies – who are competing for the same investment dollars. The credit ratings assigned by rating agencies indicate their opinions of a company's ability to meet its financial obligations. Rating agency opinions are considered valuable by potential investors because they represent independent, third-party opinions that are based upon a consistent approach to the evaluation of company risk over time. Ratings affect the number of potential investors and the cost of a company's debt, and they offer important insight into a company's investment risk in the past and future.

During the period 2016 to 2021 year to date (YTD)[2], debt investors have provided approximately $676 billion of capital investment to the U.S. utility sector. Capital provided from these investors allows utilities to fund a portion of their capital investment programs. See Chart 1 below.

[2] As of September 28, 2021.

Chart 1: 2014-August 2020 Debt Amount Issued to the U.S. Utility Sector[3]



In order to attract capital at favorable rates in a competitive environment, protecting and maintaining NSPM's credit ratings is critical. This point becomes even more critical in a volatile market environment, as recently evidenced during the COVID-19 pandemic. Utilities with higher credit ratings are associated with reduced risk, which attract investors at a lower cost of debt (i.e., lower average credit spreads) and favorably positions such utilities relative to lower-rated comparable companies. Generally, the stronger the Company's credit ratings, the larger the pool of investors willing to consider investing in the Company's debt and the less the Company will need to pay in fees and interest in order to issue debt. Investment-grade credit ratings are crucial because the cost of debt increases very rapidly – and the number of potential investors decreases substantially – for those companies rated near the bottom of or below investment grade.

[3] Source: Bloomberg

Further, credit ratings take on greater importance when economic conditions worsen and access to capital markets becomes more difficult. As credit availability tightens, investors become increasingly more selective regarding which companies qualify for their investment dollars. Therefore, lower credit ratings reduce or eliminate access to capital markets and significantly increase the cost of capital during times of market distress.

Q. HOW DO CREDIT RATINGS AFFECT NSPM'S COST OF CAPITAL?

A. LTD is priced based on the underlying Treasury rate plus a credit spread, which is primarily based on NSPM's credit rating and investors perception of the Company. In general, the lower the credit rating, the higher the credit spread. Issuing debt at a higher rate will increase the cost of LTD for NSPM, which is ultimately paid by NSPM's customers.

Equity investors also look at credit ratings. Because the income available to common equity holders is subordinate to debt obligations, the weakening of a company's creditworthiness also increases the cost of equity.

Ultimately, customers of the higher-rated utility benefit from the lower capital costs as these costs are ultimately borne by customers.

Q. DO CREDIT SPREADS DIFFER BASED ON CREDIT RATINGS?

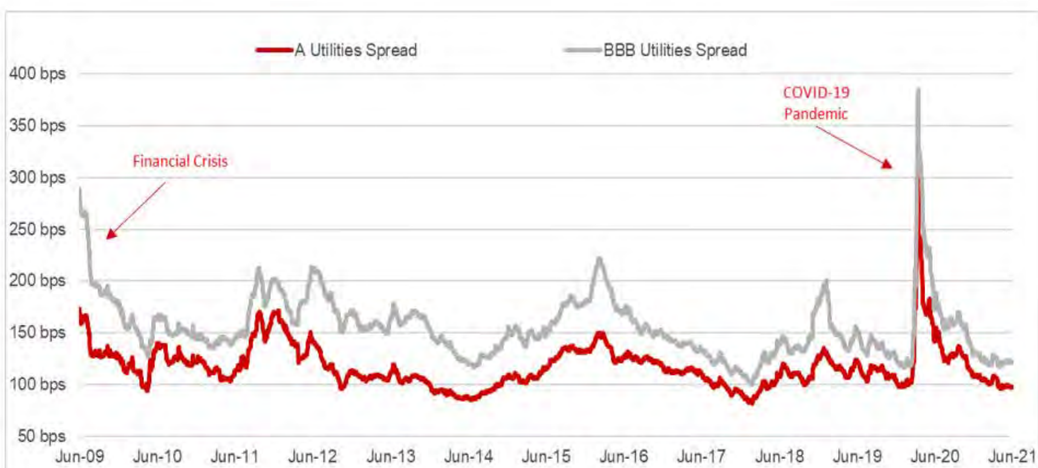
A. Yes. Lower credit ratings are seen as riskier and therefore investors demand a higher spread. Chart 2 below shows that, in general, the credit spreads of BBB rated utility companies are historically wider than those of A rated utility companies, especially in times of market volatility.[4] For example, the average

[4] Source: Bloomberg

difference in credit spreads between A and BBB rated utilities over the course of June 2009 to June 2021 (i.e., the timeframe displayed in the chart below) is approximately 40 basis points. Howevere, in periods of market volatility, the credit spread difference between A and BBB rated utilities can increase dramatically. In June 2009, the average difference in credit spreads between A and BBB rated utilities was approximately 100 basis points. More recently, towards the second half of March 2020, due to the market volatility related to the COVID-19 pandemic, the difference in credit spreads was approximately 75 basis points.

Chart 2: A vs. BBB Rated Utility Spreads

June 2009 – June 2021



Q. HAVE NSPM'S FINANCIAL STRENGTH AND CREDIT RATINGS HAD A POSITIVE EFFECT ON ITS COST OF LTD AND ITS RECENT LTD ISSUANCES?

A. Yes. NSPM's historical financial strength and credit ratings have had a positive effect on both NSPM's weighted cost of LTD and the rates for its recent LTD issuances. These effects confirm that customers and investors have a common interest in maintaining NSPM's financial strength.

Maintaining a strong balance sheet and credit metrics, and otherwise meeting expectations of the investor community, has enabled NSPM to secure more favorable borrowing costs, which lowers overall costs and provides substantial long run benefits to customers.

Q. HOW IS A CREDIT RATING ESTABLISHED?

A. Credit rating agencies assign credit ratings based on in-depth analysis and review. The analysis centers on two main areas: qualitative analysis and quantitative analysis. The qualitative side is the assessment of business risk, which is comprised first of the broad risks prevailing at the country, industry and state level. The issuer's more specific risk within its business and economic environment is then considered. For a utility, regulatory risk is the most significant business risk. The quantitative side of the analysis examines financial ratios to analyze the financial risk of the issuer.

Business risk and financial risk can be viewed as complementary sides of the total risk or investment risk of an entity, so that more of one risk must be offset by less of the other risk to arrive at a specific rating. Because regulation has a significant impact on the financial results of utilities, regulatory risk is a key consideration in ratings outcomes and receives significant attention from credit rating agencies.[5]

Q. HOW MUCH WEIGHT IS PLACED ON REGULATORY RISK BY CREDIT RATING AGENCIES?

A. For Moody's, regulatory risk constitutes up to 60 percent of the credit profile,

[5] Schedule 7 at 2 and 4-5 and Schedule 8 at 4.

and for S&P, it is up to 80 percent.[6] Both focus on the basic regulatory framework, including (1) the legal foundation for utility regulation, (2) the ratemaking policies and procedures that determine how well the utility is afforded the opportunity to earn a reasonable return with reasonable cash flow, and (3) the history of regulatory behavior by commissions applying those laws, policies and procedures. Then, they examine the mechanics of regulation, particularly the rate-setting process.

Q. WHAT OTHER CONSIDERATIONS GO INTO DETERMINING REGULATORY RISK?

A. Credit rating agencies also place high value on transparency, predictability, and consistency in regulatory outcomes.[7] Utilities fund capital expenditures primarily with long-dated maturities to match the long-lived assets. Credit rating agencies regard fixed income investors (who extend credit over long periods) as their primary audience and strive to rate LTD as accurately as possible. Utility investors value ratings that are stable and accurate. Regulatory frameworks and practices that are viewed as constructive, transparent, consistent and predictable allow rating agencies to more accurately project future cash flows and debt leverage and will result in a better business risk profile. This predictability offers creditors the ability to accurately assess risk over most of the debt's term and improves the ability of the company to manage its business activities and capital program for the long-term benefit of ratepayers.

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[6] Schedule 9 at 4 (Regulatory Framework (25%) + Ability to Recover Costs and Earn Returns (25%) + Diversification (10%)) and Schedule 10 at 6,9 (Competitive Advantage (60%) + Scale, Scope and Diversity (20%)).

[7] Schedule 9 at 10 and Schedule 10 at 6-8.

Q. HAVE CREDIT RATING AGENCIES COMMENTED ON THE IMPORTANCE OF THE REGULATORY FRAMEWORK IN EVALUATING A UTILITY'S FINANCIAL INTEGRITY?

A. Yes. S&P has noted that the regulatory framework "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."[8] S&P observes further that "[w]e 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."[9]

Q. SHOULD THE COMMISSION CONSIDER REGULATORY RISK WHEN DECIDING THE OUTCOME OF THIS PROCEEDING?

A. Yes. Credit rating agencies have emphasized the importance of balanced, consistent, and constructive outcomes in utility rate proceedings. Such regulatory outcomes convey to the rating agencies the credit-positive relationships between companies and commissions, which in turn may lower the perceived risk for external investors and result in lower debt costs.

Q. WHAT FINANCIAL CONSIDERATIONS CONSTITUTE THE QUANTITATIVE SIDE OF CREDIT ANALYSIS?

A. Credit analysis focuses on cash flow. Credit analysts strive to understand the cash-flow dynamics of a company's financial results, because servicing debt requires cash not just earnings. A recent example of this is the effect of tax

[8] Schedule 10 at 6.
[9] Schedule 10 at 6.

reform on utilities, which placed downward pressure on utility ratings because of its negative cash-flow impact despite relatively neutral earnings implications. The primary measure that rating agencies use for most cash-flow metrics is cash from operations (CFO) or some derivation of it.[10] The other major element of financial risk to a credit analyst is the total amount of debt or debt-like obligations (also referred to as imputed or off-balance sheet debt) on the issuer's balance sheet. Items that the rating agencies regard as debt-like adjustments include lease liabilities, long-term power purchase obligations, pension obligations, and asset-retirement obligations.

Q. WHAT ARE THE PRIMARY FINANCIAL METRICS THAT CREDIT RATING AGENCIES ANALYZE?

A. The primary financial metrics evaluated by the major credit rating agencies include some version of the following coverage ratios: (i) the ratio of funds from operations or cash from operations to total debt (FFO/Total Debt or CFO/Debt); (ii) the ratio of funds from operations or cash from operations to interest (FFO/Interest or CFO/Interest) and; (iii) the ratio of debt to earnings before interest, taxes, depreciation, and amortization (Debt/EBITDA). These financial metrics are a composite measure of the utility's ability to manage its debt burden over time and to meet its financial obligations as they come due. The greater the *business* risk, the stronger these financial metrics must be to maintain the same credit ratings to provide sufficient evidence to the credit rating agencies and investors that the company can withstand the financial effect of both macroeconomic and company-

[10] For Moody's, their derivation of the CFO measurement is "CFO pre-working capital." S&P refers to this measure as funds from operations (FFO). Both Moody's and S&P compare there derivation of CFO to the overall debt burden.

specific risks.

Q. WHAT TYPES OF DEBT OBLIGATIONS DO RATING AGENCIES INCLUDE IN THEIR CREDIT METRICS CALCULATIONS?

A. The total debt calculated by rating agencies includes debt and debt-like obligations, including on-balance sheet obligations such as finance and operating leases, as well as off-balance sheet obligations. Off-balance sheet obligations are payment obligations (such as long term purchase power obligations, pension obligations, and asset retirement obligations) that do not appear on the balance sheet as debt; however, rating agencies may treat them as debt because the utility has little or no discretion whether to pay for these obligations.[11]

Q. WHAT IS THE SIGNIFICANCE TO THIS RATE CASE OF THE RATIOS THE CREDIT RATING AGENCIES EVALUATE?

A. This rate case outcome will affect both the business risk and the credit metrics. Investors and credit rating agencies will assess the rate case outcome to determine if the regulatory risk has changed. The rate case outcome will also allow investors and credit rating agencies to update their projections and credit metrics to determine whether a company will be able to service its existing debt obligations at the required level and will have the flexibility to take on incremental debt. Including existing off-balance sheet obligations in calculating a company's total debt affects many of the financial metrics the rating agencies rely upon. In general, the higher the proportion of debt in a capital structure, the more downward pressure on cash flow metrics and credit ratings, and upward pressure cost of capital to the utility and its customers.

[11] See Schedules 9, 10, and 11 for a discussion of adjustments for off-balance sheet obligations.

Q. PLEASE EXPLAIN THE RATING AGENCY SCALES.

A. Credit rating agencies provide ratings for both the business entity as a whole and for the various debt issuances of the entity. The investment-grade rating categories include the High Grade (Triple-A and Double-A) and the Medium Grade category (Single-A and Triple-B ratings). The ratings are generally further delineated by S&P through the use of pluses or minuses to show a company's relative standing within the categories, while Moody's uses numbers to show a company's standing within a category. The highest investment-grade rating is AAA; the lowest investment-grade rating is BBB-. Debt rated BB+ or below is considered speculative grade or junk bonds.

Q. WHAT ARE THE COMPANY'S CURRENT CREDIT RATINGS?

A. The Company's current credit ratings are:

Table 4

NSPM Current Credit Ratings

	Fitch	**Moody's**	**Moody's S&P Equivalent**	**S&P**
Corporate Rating	A-	A2	A-	A-
Senior Secured	A+	Aa3	A	A

There have been no changes in the credit ratings since the last MYRP filing.

Q. HOW DO THE COMPANY'S CREDIT METRICS COMPARE TO THE S&P AND MOODY'S CRITERIA?

A. Exhibit___(PAJ-1), Schedule 12, Page 1, shows NSPM's forecasted credit metrics as compared to S&P guidelines. The metrics are within the target ranges for NSPM's current credit ratings. Exhibit___(PAJ-1), Schedule 12, Page 2, shows NSPM's forecasted credit metrics as compared to Moody's guidelines. The main metrics are generally within these target ranges. Overall, the Company expects that its recommended capital structure and the forecasted financial metrics will continue to support and maintain its current credit ratings over the 2022 to 2024 time period.

Q. WHY IS IT IMPORTANT FOR NSPM TO MAINTAIN ITS A- CORPORATE RATING?

A. Earlier in my Direct Testimony, I demonstrated that the credit spreads between an A and BBB rated company can be significant, especially during times of market volatility or distress. This is a real cost that affects what rates the customers pay. To further support this position, Dr. Roger Morin, a noted expert on regulatory finance, analyzes the optimal capital structure for utilities in his book *New Regulatory Finance*. Based on that analysis, Dr. Morin concludes that an A rated utility is in the best interest of the customers and utilities:

> "The message from the model is clear: over the long run, a strong A bond rating will minimize the pre-tax cost of capital to ratepayers. Long term achievement of at least an A rating is in the electric utility company's and ratepayers' best interests.
>
> The model results show that on an incremental cost basis, a strong A bond rating generally results in the lowest pre-tax cost of capital for electric utilities, especially under adverse economic conditions, which are far more relevant to the question of capital structure."[12]

[12] Roger A. Morin, *New Regulatory Finance* 515 (2006).

Q. WHAT IS THE SIGNIFICANCE OF RATEMAKING-RELATED FINANCIAL METRICS SUCH AS ROE, EQUITY RATIO/CAPITAL STRUCTURE, AND TIMELINESS AND RELIABILITY OF COST RECOVERY?

A. I will address each component in turn:

- First, the authorized ROE and equity ratio affect NSPM's earnings and cash flows, which directly affect its ability to fund capital investment. In addition to credit ratings, investors also assess the capital structure and ROE when making judgements about the credit quality of a regulatory jurisdiction. As such, the ROE/equity ratio combination is a powerful and effective communication tool to underscore the interest of regulators in attracting capital to provide safe, reliable and environmentally-sound electric service to customers.
- Second, the capital structure and authorized costs directly affect all NSPM's key credit metrics because either total debt or interest expense is a component of each of the primary credit metrics that rating agencies analyze. The credit rating agencies also evaluate the relative amounts of debt and equity in the capital structure to determine whether a company is appropriately capitalized given its business risk profile and to determine whether the company has the ability to make interest payments, repay existing debt and issue additional new debt to fund its utility capital expenditures. The credit rating agencies are very concerned with a company's liquidity to meet its short-term capital needs under conditions of financial stress, and they factor in the debt portfolio maturity schedule and other future obligations as part of this assessment.
- Third, debt and equity investors expect NSPM to be able to recover its costs in a timely manner and to have a reasonable opportunity to earn its authorized ROE. Investors and rating agencies track the decisions of

regulatory agencies relating to capital structure, cost of debt, ROE, cost recovery and forward-looking cost recovery mechanisms. They categorize the state regulatory environments in their assessment of the relative risks of different utility investment opportunities.

- Finally, investors prefer certainty and will demand a higher return for what they perceive as greater risk. For regulated utilities, investors prefer constructive, consistent, transparent and predictable regulatory environments because this reduces risk and enables investors to generate predictable returns.

Q. CAN YOU FURTHER EXPLAIN WHY THE COMMISSION'S DECISIONS FOR NSPM ARE PARTICULARLY IMPORTANT TO THE INVESTOR COMMUNITY?

A. Investors – both debt and equity – and credit rating agencies understand the importance of the regulatory environment on the business risks of utilities. Credit rating agencies and investors also know that NSPM has investments weighted heavily toward its electric business and that NSPM's customers are concentrated in Minnesota, making the Minnesota retail electric jurisdiction NSPM's primary jurisdiction. Finally, rating agencies and bond and equity investors know that the Commission is fully informed about NSPM's investment plans through the various dockets before the Commission. As a result, these agencies and investors will likely consider the Commission's decisions regarding the financial components of the overall ROR and electric rates as a reflection of the level of support for NSPM's investment plans, including the investments necessary to carbon reduction goals. Therefore, the Commission's decisions not only have an important impact on NSPM's ability to maintain its financial integrity and allow us to access low cost capital, they will impact NSPM's ability to achieve its broader business and environmental goals.

V. PROPOSED CAPITAL STRUCTURE, COST OF DEBT, AND RATE OF RETURN

Q. PLEASE SUMMARIZE THE MOST SIGNIFICANT POINTS YOU DISCUSS IN THIS SECTION OF YOUR DIRECT TESTIMONY.

A. The most significant points I discuss include the following:

- The components of LTD, STD, and common equity for 2022, 2023 and 2024 have been determined using the same methodology that have been used in prior rate cases.
- NSPM's proposed capital structures for 2022, 2023 and 2024 are very consistent to the capital structure adopted in the last rate case.
- The costs of LTD and STD have also been determined using the same methodology that have been used in prior cases.
- The size of NSPM's short term credit facility is reasonable and has not changed since the last MYRP.
- The Utility Money Pool provides public interest benefits to NSPM's customers.

Q. PLEASE SUMMARIZE THE COMPONENTS OF NSPM'S RECOMMENDED CAPITAL STRUCTURE AND ROR.

A. NSPM's proposed 2022, 2023 and 2024 capital structures include LTD, STD, and common equity. NSPM's proposed revenue requirement for 2022 reflects an overall cost of capital or ROR of 7.31 percent, which includes NSPM's average common equity ratio of 52.50 percent and a 10.20 percent ROE as recommended in Mr. D'Ascendis's Direct Testimony. NSPM's proposed ROR for 2023 is 7.28 percent and for 2024 is 7.30 percent, again including NSPM's average common equity ratio of 52.50 percent and the 10.20 percent ROE recommended by Mr. D'Ascendis.

Q. HOW DO NSPM'S 2022, 2023 AND 2024 CAPITAL STRUCTURES COMPARE WITH THE CAPITAL STRUCTURES REFLECTED IN PAST RATE CASES?

A. The capital structures for all three years are comparable to the capital structure approved by the Commission in NSPM's 2013 rate case (Docket No. E002/GR-13-868) and those reflected in the Settlement approved by the Commission in the 2015 rate case. The proposed 52.50 percent equity ratio for all three years match the equity ratios approved in those cases. The LTD ratios for years 2022 through 2024 range from 46.50 to 47.08 percent, compared to 2013 and 2015 rate case LTD ratios ranging from 45.60 to 46.41 percent. Finally, the STD ratios of 0.42 to 1.00 percent are comparable to the 2013 and 2015 ratios, which ranged from 1.09 to 1.90 percent.

Q. WHAT METHODOLOGY DID NSPM USE TO DEVELOP BALANCES AND COSTS FOR THE VARIOUS COMPONENTS OF CAPITAL STRUCTURE?

A. NSPM's methodology in this case is consistent with the calculations used and approved by the Commission in prior rate cases. Key points are identified below:

- 2022 and 2023 future long and short-term debt interest rates are based on the average between July 2021 Global Insight forecast and July 2021 Bloomberg forward curve with an added credit spread (which is based on the current credit rating and reflects current market information). 2024 future long and short-term debt interest rates are based on July 2021 Global Insight forecast with an added credit spread. The July 2021 Global Insight forecast and July 2021 Bloomberg forward curve is attached as Exhibit___(PAJ-1), Schedule 13.

- For forecast purposes, STD is in the form of commercial paper.
- STD balances are based on the average of month-end balances for the 12 months in the respective year.
- LTD balances are based on the average of month-end balances for the 12 months in the respective year and include forecasted LTD issuances and retirements during that period.
- LTD costs include the coupon rate on all bonds expected to be outstanding for each month of the respective year. In addition to the interest expense, the cost of LTD also includes amortization expense for debt issuance costs, discounts or premiums, losses on reacquired debt, gains and losses from hedging transactions, and the annual amortization of the upfront fees associated with NSPM's multi-year credit agreement.
- Common equity balances represent the average of 13 month-end equity balances from December of the prior year through December of the year analyzed. The common equity balance averages the accounting month-end balances consistent with Generally Accepted Accounting Principles (GAAP) and eliminates the non-regulated investments.

1. LTD

Q. WHAT ARE NSPM'S RECOMMENDED 2022-2024 LTD BALANCES AND COSTS?

A. See NSPM's recommended LTD balances and costs for 2022 through 2024 included in Table 5, as shown on Exhibit__(PAJ-1), Schedules 4, 5 and 6, respectively, Page 1 of 1.

Table 5

Recommended 2022 through 2024 LTD Balances and Costs

	LTD Balance	LTD Cost
2022 Test Year	$6.9 billion	4.13%
2023 Plan Year	$7.3 billion	4.12%
2024 Plan Year	$7.7 billion	4.09%

Q. ARE THERE ISSUANCES OR RETIREMENTS OF LTD PLANNED FOR 2022 THROUGH 2024?

A. Yes, NSPM plans to issue $550 million of new LTD in 2022, $850 million in 2023 and $450 million in 2024. NSPM has a $300 million debt retirement scheduled in 2022 and a $400 million debt retirement scheduled in 2023.

Q. HOW DOES THE COMPANY DETERMINE ITS LTD ISSUANCES?

A. NSPM forecasts its financing needs over a multi-year period. NSPM generally issues LTD in years when an existing long-term bond is maturing or if existing higher coupon debt can be refinanced at a lower interest rate. In addition, NSPM will issue LTD to replace STD when the STD levels approach or remain above an "index-eligible" bond size of $300 million. All of these factors can affect the amount and timing of a specific bond offering.

When determining the maturity of a new bond, NSPM considers the existing debt portfolio maturity profile, market conditions, investor demand, the life of the underlying asset portfolio, and the effects on the cost of LTD on the customer. NSPM reviews the existing debt portfolio maturity profile and identifies potential years where maturities are not already scheduled to occur.

NSPM staggers new LTD maturities to mitigate refinancing risk or the risk of having large future maturities in any one year that could be exposed to capital market volatility and the associated interest rate risk.

Q. PLEASE EXPLAIN THE TERM "INDEX ELIGIBLE" AND WHY IT IS IMPORTANT.

A. To be included in the Barclays Capital Aggregate Bond Index, a bond must be a minimum size of $300 million. Bonds that trade as a component of the index are more liquid and will generally be priced at a lower credit spread over prevailing U.S. Treasury rates than less liquid bonds, resulting in lower cost to customers.

Q. DOES NSPM CONSIDER THE POSSIBILITY OF EARLY RETIREMENT OF COMPONENTS OF ITS LTD PORTFOLIO?

A. Yes. For example, in 2020, NSPM retired a bond that had provisions that allowed the Company to "call" the bonds without incurring significant added financial obligations known as "make whole" redemption obligations. The bonds currently in the NSPM debt portfolio either: (i) have no call options; (ii) are only callable at par value 3 to 6 months prior to maturity; or (iii) have make whole redemption provisions that are too expensive to exercise because they result in very large premium payments to existing debt holders. NSPM continues to monitor its LTD portfolio to take advantage of refinancing opportunities that could result in lower customer costs.

2. STD

Q. WHAT IS NSPM'S RECOMMENDED 2022 THROUGH 2024 STD BALANCES AND ASSOCIATED COSTS?

A. See NSPM's recommended STD balances and costs for 2022 through 2024 included in Table 6, as also shown on Exhibit__(PAJ-1), Schedule 14, 15 and 16, respectively, Page 1 of 1.

Table 6

Recommended 2022 through 2024 STD Balances and Costs

	STD Balance	STD Cost
2022 Test Year	$88.9 million	0.94%
2023 Plan Year	$156.6 million	0.80%
2024 Plan Year	$68.3 million	1.47%

Q. HOW WAS THE 2022 THROUGH 2024 COST OF STD DETERMINED?

A. The cost of STD includes interest expense for commercial paper and the monthly financing fee associated with NSPM's June 2019 "Amended and Restated Credit Agreement" for its participation in the credit facility, which provides the back-up liquidity required for its commercial paper program. See the Company's Exhibit__(PAJ-1), Schedule 14, 15 and 16, respectively, Page 1 of 1 for a break-out of the STD cost between monthly interest expense relating to commercial paper and the monthly fee expense relating to the credit facility fees.

Q. HAS THE SIZE OF THE CREDIT FACILITY CHANGED SINCE THE PRIOR CASE?

A. No. NSPM's credit facility remains at the $500 million level. To determine the size of NSPM's credit facility, NSPM considers liquidity requirements to evaluate the amount of short term credit capacity required, such as: (i) the total capital commitments over the life of the revolving credit agreement, including projected capital investment and scheduled LTD maturities; (ii) the projected level and volatility of fuel purchase requirements; and (iii) the liquidity required to manage variability in operating cash flow due to changes in sales and operating expenses. Currently, these factors support the sizing of the credit facility at $500 million; however, the size of the credit facility may need to be reassessed if these factors change.

Q. DOES NSPM'S USE OF COMMERCIAL PAPER REDUCE THE REQUIRED LEVEL OF NSPM'S CREDIT FACILITY?

A. No. NSPM expects to have continued access to the capital and commercial paper markets, but it is necessary to have adequate back up liquidity in the event of a capital market disruption. For example, the 2008 capital market crisis caused commercial paper to become unavailable for a period of time. In a more recent example, during March 2020, as a result of the COVID-19 pandemic, commercial paper markets became very volatile and the cost of commercial paper increased dramatically as shown in Chart 3 below. If comparable events occurred again, or commercial paper required unreasonable terms or costs, NSPM would be reliant on its credit facility for its liquidity needs.

Chart 3: A2/P2 Overnight Commercial Paper Rates

March-April 2020[13]

A credit facility is required in order to backstop commercial paper facilities. In other words, if NSPM was not able to repay its maturing commercial paper, it would be required to draw down its credit facility in order to meet that obligation. Commercial paper is almost always used instead of direct drawing on the credit facility because of its lower cost. Since the credit facility is a backstop to commercial paper, the amount of commercial paper issued cannot exceed the limit of the credit facility. Any outstanding commercial paper reduces the amount available to draw under the credit facility.

Q. DOES NSPM PARTICIPATE IN A UTILITY MONEY POOL WITH OTHER OPERATING UTILITY SUBSIDIARIES OF XEI?

A. Yes. The Utility Money Pool is a short-term intercompany revolving credit facility that allows for coordination and provision of some short-term cash and working capital for NSPM, Northern States Power Company, a Wisconsin corporation (NSPW), Public Service Company of Colorado (PSCo) and

[13] Source: www.federalreserve.gov

Southwestern Public Service Company (SPS).

Q. HAS THE COMMISSION REVIEWED AND APPROVED NSPM'S PARTICIPATION IN THE UTILITY MONEY POOL?

A. Yes. The Commission's July 9, 2004 Order in Docket No. E002/AI-04-100 approved participation in the Utility Money Pool, and required NSPM to demonstrate in future rate cases that NSPM's participation in the Utility Money Pool continues to be consistent with the public interest. NSPM has submitted the required information in this case and in all prior rate cases since 2004. NSPM also submits information regarding its participation in the Utility Money Pool for Commission review and approval in its annual capital structure petition filings.

Q. IS THE UTILITY MONEY POOL CONSISTENT WITH THE PUBLIC INTEREST?

A. Yes. The Utility Money Pool provides additional flexibility and allows for potential cost savings and efficiencies without limiting access to existing financing. Participants are not obligated to lend to or borrow from the Utility Money Pool. However, it is available for use when it is most efficient, in situations when it provides benefits such as a lower cost of borrowing, or more flexibility regarding the terms of borrowing. NSPM's lending limits are also subject to approval by both the Commission and the Federal Energy Regulatory Commission.

Q. DOES THE UTILITY MONEY POOL PROVIDE A SUBSTITUTE FOR THE NSPM CREDIT FACILITY IN RELATION TO NEEDED LIQUIDITY?

A. No. Since there is no obligation for any participant to provide funds to the Utility Money Pool, it does not provide the assurance of available cash that is needed by NSPM, and thus does not provide a substitute source of liquidity for NSPM's credit facility and commercial paper program.

Q. DOES NSPM'S PARTICIPATION IN THE UTILITY MONEY POOL IMPOSE RISKS ON NSPM?

A. No. The borrowings under the Utility Money Pool are payable on demand. If anything, NSPM's participation in the Utility Money Pool provides additional access to liquidity (and usually at more favorable rates) and thus, reduces risk that may be caused by various macroeconomic events.

Q. HAVE YOU PREPARED A SCHEDULE SHOWING BORROWING AND LENDING BETWEEN NSPM AND THE UTILITY MONEY POOL?

A. Yes. Exhibit___(PAJ-1), Schedule 17, provides a record of Utility Money Pool activity, including lending to and borrowing from the Utility Money Pool from January 2019 through June 2021.

3. Common Equity

Q. HOW DID YOU DETERMINE NSPM'S 2022 THROUGH 2024 COMMON EQUITY BALANCES?

A. Consistent with prior rate case methodology, the proposed 2022 test year and 2023 and 2024 plan years' common equity balances reflect the average of 13 month-end equity balances from December of the previous year through December of the respective year and eliminates the non-regulated investments. See NSPM's recommended common equity balances by month for 2022 through 2024 by referencing Exhibit___(PAJ-1), Schedules 18, 19 and 20, respectively.

Q. HAS XEI ISSUED COMMON STOCK IN THE LAST FEW YEARS?

A. Yes. In September 2018, XEI issued approximately $225 million of common stock through a $300 million SEC-registered "At the Market" program under which XEI issued common stock to the public from time to time at then-prevailing market prices. XEI entered into a forward equity agreement for approximately $460 million in November 2018, which was settled in August 2019. Additionally, in November 2019, XEI entered into forward sales agreements in connection with a completed $743 million public offering of 11.8 million shares of Xcel Energy common stock. In November 2020, XEI settled the forward sales agreement.

Q. HAVE YOU PROVIDED INFORMATION REGARDING FLOTATION COSTS FOR PUBLIC AND NON-PUBLIC EQUITY ISSUANCES BY XEI?

A. Yes. Information regarding flotation costs for public and non-public offerings by XEI is included in Exhibit___(PAJ-1), Schedule 21. This information was used by Mr. D'Ascendis in his testimony regarding his flotation cost adjustment.

VI. INVESTOR RELATIONS EXPENSES

Q. CAN YOU PLEASE ALSO DISCUSS THE COMPANY'S INVESTOR RELATIONS EFFORTS AND THE EXPENSES YOU EXPECT TO INCUR IN THE 2022 TEST YEAR AND IN THE 2023 AND 2024 PLAN YEARS?

A. Yes. NSPM will incur investor relations expenses in 2022 through 2024 due to the need to keep the credit rating agencies fully informed regarding NSPM's business and financing plans and to maintain strong investor demand for NSPM's LTD securities. The Investor Relations team also incurs costs for shareholder services and interactions with fixed income investors. These efforts will enable NSPM to issue LTD securities at favorable costs, as evidenced by NSPM's very low cost of LTD. Additionally, the Investor Relations group will continue to support the Company's equity program, and customers receive the benefit of improved proceeds as a result of obtaining favorable prices from the issuance of stock.

Q. ARE THESE DISCRETIONARY EXPENSES?

A. No. A company with publicly-traded equity must engage in investor relations activities, including but not limited to: (i) the listing of shares of XEI on the National Association of Securities Dealers Automated Quotations (NASDAQ); (ii) stock transfer agent services associated with the issuance of new common shares to investors, providing shareholders online access to accounts, and maintaining the list of registered shareholders; and (iii) an annual shareholders meeting.

Q. IS IT APPROPRIATE TO INCLUDE THESE EXPENSES AS PART OF THE COMPANY'S COST OF PROVIDING ELECTRIC SERVICE TO MINNESOTA RATEPAYERS?

A. Yes. These are unavoidable, just and reasonable expenses that should be included in NSPM's cost of service for ratemaking purposes. The Company incurs these expenses as a necessary part of providing cost-effective service to its customers; they are not expenses incurred to benefit shareholders.

Q. BUT ISN'T NSPM REQUESTING RECOVERY OF ONLY HALF OF THESE EXPENSES?

A. Yes. Company witness Mr. Benjamin C. Halama's testimony, and the Company's rate request, reflects recovery of only 50 percent of these expenses in this case. NSPM has removed 50 percent of these expenses, consistent with past Commission decisions on this topic and due to the desire to minimize controversy in this proceeding. However, NSPM continues to view these as just, reasonable and necessary expenses.

VII. CONCLUSION AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend that the Commission approve NSPM's recommended 2022 test year capital structure with 52.50 percent common equity and an overall rate of return of 7.31 percent, as follows:

2022 Test Year

Recommended Capital Structure Ratios and Costs

(as presented in Table 1 on Page 4)

	Percent of Total Capital	Cost	Weighted Cost
STD	0.61%	0.94%	0.01%
LTD	46.89%	4.13%	1.94%
Common Equity	52.50%	10.20%	5.36%
Total Capital	100.00%		7.31%

I also recommend that the Commission approve a proposed 2023 capital structure with 52.50 percent common equity and an overall rate of return of 7.28 percent, as follows:

2023

Recommended Capital Structure Ratios and Costs

(as presented in Table 2 on Page 4)

	Percent of Total Capital	Cost	Weighted Cost
STD	1.00%	0.80%	0.01%
LTD	46.50%	4.12%	1.91%
Common Equity	52.50%	10.20%	5.36%
Total Capital	100.00%		7.28%

And lastly, I recommend that the Commission approve a proposed 2024 capital structure with 52.50 percent common equity and an overall rate of return of 7.30 percent, as follows:

2024

Recommended Capital Structure Ratios and Costs

(as presented in Table 3 on Page 5)

	Percent of Total Capital	Cost	Weighted Cost
STD	0.42%	1.47%	0.01%
LTD	47.08%	4.09%	1.93%
Common Equity	52.50%	10.20%	5.36%
Total Capital	100.00%		7.30%

NSPM's proposed capital structures and overall costs of capital are reasonable and meet the Commission general standards of reasonableness used in decision making. The capital structures are largely similar to the capital structure that

NSPM has managed to for nearly a decade. These capital structures are market based and consistent with prior Commission decisions for NSPM and with capital structures of other comparable companies. The recommended capital structures will continue to support NSPM's financial integrity as demonstrated through strong bond ratings and lower costs of debt, while simultaneously enabling NSPM to make substantial capital investments in the utility infrastructure, including renewable energy. Finally, NSPM has not materially changed its capital structure since 2009 and the Commission has reviewed and approved its equity ratio in the past four electric rate case proceedings.

I also recommend that the Commission allow partial recovery of investor relations costs in rates as NSPM has proposed.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?
A. Yes, it does.

Statement of Qualifications

Schedule 1

Paul A. Johnson

I received my Bachelor of Science in Business from Winona State University and my MBA from the University of St. Thomas. I am a CFA charter holder and passed the CPA and CMA exams.

I am the Vice President of Investor Relations and Treasurer and have held this position since July 2021. Prior to this role, I served in the following roles during my tenure at Xcel Energy: Vice President, Investor Relations (2013-2021); Vice President, Investor Relations and Business Development (2012-2013); Vice President, Investor Relations and Financial Management (2011-2012); Managing Director of Investor Relations and Assistant Treasurer (2008-2011); Managing Director of Investor Relations (2007-2008); Director of Investor Relations (2001-2006); Director of External Reporting (1998-2001); Controller and Assistant Treasurer for Energy Masters (1995-1998); and Administrator in Internal Reporting (1992-1995).

PROPOSED TEST YEAR 2022 COST OF CAPITAL

Capitalization:	($000's) Amount	Percent of Total Capitalization	Cost of Capital	Weighted Cost of Capital*
Long-Term Debt	$6,873,445	46.89%	4.13%	1.94%
Short-Term Debt	$88,882	0.61%	0.94%	0.01%
Total Debt	$6,962,327	47.50%		1.95%
Net Common Equity	$7,695,202	52.50%	10.20%	5.36%
Total Capitalization	$14,657,529	100.00%		7.31%

Short Term Debt and Long Term Debt Amounts are 12 Month Average Balances.
Equity Amounts are 13 Month Average Balances.

PROPOSED ADDITIONAL TEST YEAR 2023 COST OF CAPITAL

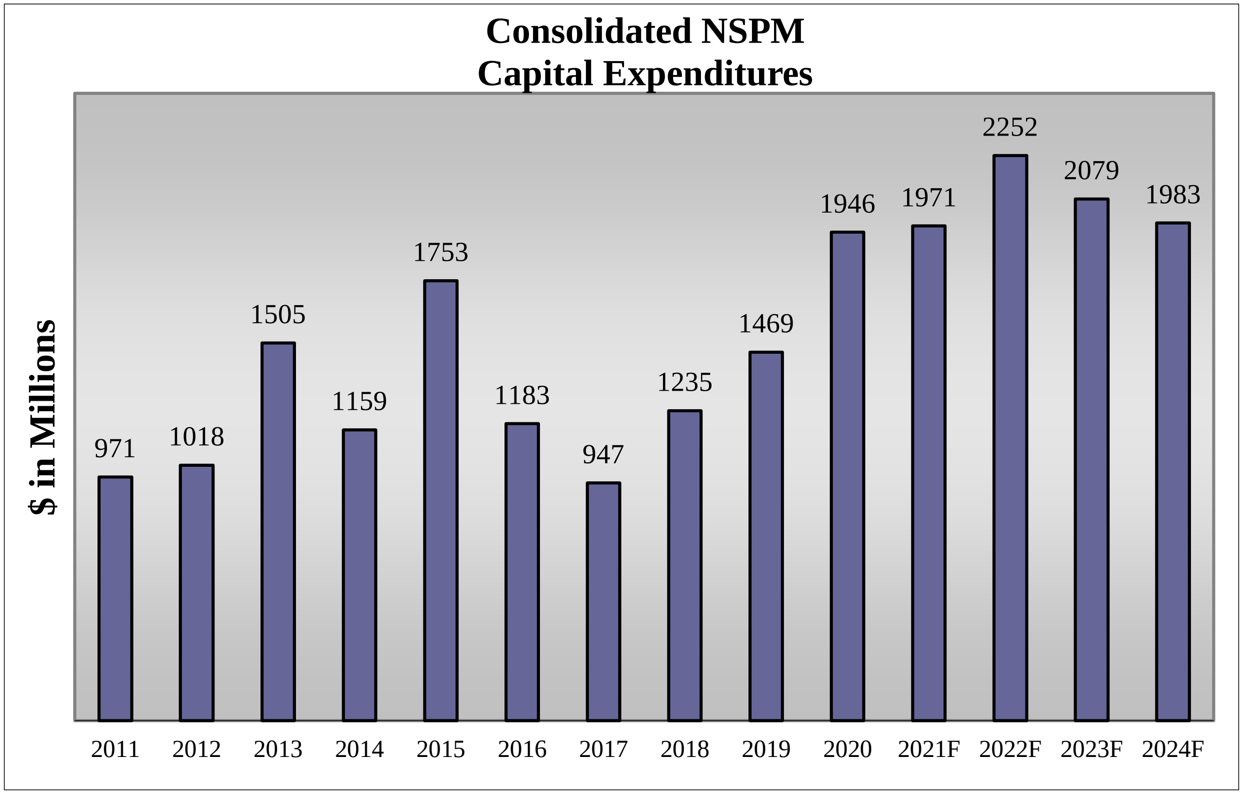
Capitalization:	($000's) Amount	Percent of Total Capitalization	Cost of Capital	Weighted Cost of Capital*
Long-Term Debt	$7,253,518	46.50%	4.12%	1.91%
Short-Term Debt	$156,591	1.00%	0.80%	0.01%
Total Debt	$7,410,109	47.50%		1.92%
Net Common Equity	$8,190,137	52.50%	10.20%	5.36%
Total Capitalization	$15,600,246	100.00%		7.28%

Short Term Debt and Long Term Debt Amounts are 12 Month Average Balances.
Equity Amounts are 13 Month Average Balances.

PROPOSED ADDITIONAL TEST YEAR 2024 COST OF CAPITAL

Capitalization:	($000's) Amount	Percent of Total Capitalization	Cost of Capital	Weighted Cost of Capital*
Long-Term Debt	$7,702,921	47.08%	4.09%	1.93%
Short-Term Debt	$68,262	0.42%	1.47%	0.01%
Total Debt	$7,771,183	47.50%		1.94%
Net Common Equity	$8,589,208	52.50%	10.20%	5.36%
Total Capitalization	$16,360,391	100.00%		7.30%

Short Term Debt and Long Term Debt Amounts are 12 Month Average Balances.
Equity Amounts are 13 Month Average Balances.



(a) 2011 - 2020 actual 10 year expenditures = $13.2B, average spend per year = $1.319B

(b) 2016 - 2020 actual 5 year expenditures = $6.8B, average spend per year = $1.356B

(c) 2021 - 2024 forecast 4 year expenditures = $8.3B, average spend per year = $2.071B

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of Minnesota
RATE OF RETURN COST OF CAPITAL SCHEDULES
Composite Cost of Long-Term Debt
($000's)

Docket No. E002/GR-21-630
Exhibit ____(PAJ-1), Schedule 4
Page 1 of 1

2022 FORECASTED LONG TERM DEBT AND COST
as of 7/30/21

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(4) Capital Employed	Total Bond Cost: (5) Interest Charge	Total Bond Cost: Premium/ Hedge Amortization	Total Bond Cost: Discount Amortization	Total Bond Cost: Expense Amortization	Total Bond Cost: LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	230	187		249,583	17,813	-	78	63		17,953	7.19%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	330	277		149,393	9,750	-	59	49		9,858	6.60%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	210	1,314		248,475	13,125	-	16	101		13,242	5.33%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	7,561	649	2,255		404,657	25,000	545	47	162		24,665	6.10%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	991	2,162		346,848	21,700	-	66	144		21,911	6.32%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(1,851)	329	2,398		295,421	16,050	(107)	19	139		16,315	5.52%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	426	1,819		247,754	12,125	-	24	101		12,249	4.94%
Series Due August 15, 2022 (FMB) (2)	2.1500	Aug-12	Aug-22	100,000	-	8	52		99,940	2,150	-	28	191		2,370	2.37%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(30,069)	2,556	4,200		463,174	17,000	(1,496)	127	209		18,833	4.07%
Series Due May 15, 2023 (FMB)	2.6000	May-13	May-23	400,000	-	61	375		399,564	10,400	-	73	453		10,927	2.73%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	635	2,782		296,583	12,375	-	29	127		12,531	4.23%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	3,767	2,999		293,233	12,000	-	163	130		12,293	4.19%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,665	4,302		344,033	12,600	-	70	180		12,850	3.74%
Series Due Sep 15, 2047 (FMB)	3.7000	Sep-17	Sep-47	600,000	-	5,017	7,381	7,023	580,579	22,200	-	199	293	279	22,971	3.96%
Series Due Mar 1, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	10,492	7,916		581,592	17,400	-	380	286		18,066	3.11%
Series Due Jun 1, 2051 (FMB)	2.6000	Jun-20	Jun-51	700,000	-	12,286	9,132		678,582	18,200	-	425	316		18,941	2.79%
Series Due Apr 1, 2031 (FMB)	2.2500	Mar-21	Apr-31	425,000	-	1,546	4,339		419,115	9,563	-	177	498		10,238	2.44%
Series Due Apr 1, 2052 (FMB)	3.2000	Mar-21	Apr-52	425,000	-	1,511	5,692		417,797	13,600	-	51	191		13,842	3.31%
Series Due May 1, 2052 (FMB) (1)	3.3000	May-22	May-52	366,667	-	-	5,431		361,236	12,100	-	-	184		12,284	3.40%
Other Debt																
Right of Way Notes	var	var	var	413	-	-	-		413	-	-	-	-		-	0.00%
TOTAL DEBT				7,017,080	(24,360)	42,709	65,014	7,023	6,877,974	275,150	(1,059)	2,031	3,820	279	282,339	4.10%
Unamortized Loss on Reacquired Debt									(4,529)						1,020	
Fees on 5-year Credit Facility (3)									-						379	
GRAND TOTAL and COST OF DEBT									6,873,445						283,738	4.13%

(1) NSPM 2022 issuance of $550M 30 year bond, balance is 8 of 12 months.
(2) NSPM 2012 issuance of $300M 10 year bond, balance is 4 of 12 months.
(3) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.
(4) Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.
(5) Interest Expense is a Straight Interest Expense calculation.

($000's)

2023 FORECASTED LONG TERM DEBT AND COST
as of 7/30/21

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(4) Capital Employed	Total Bond Cost (5) Interest Charge	Premium/ Hedge Amortization	Discount Amortization	Expense Amortization	LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	152	124		249,724	17,813	-	78	63		17,953	7.19%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	272	227		149,501	9,750	-	59	49		9,858	6.59%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	194	1,213		248,593	13,125	-	16	101		13,242	5.33%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	7,016	602	2,092		404,322	25,000	545	47	162		24,665	6.10%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	924	2,017		347,058	21,700	-	66	144		21,911	6.31%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(1,744)	310	2,260		295,686	16,050	(107)	19	139		16,315	5.52%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	403	1,719		247,879	12,125	-	24	101		12,249	4.94%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(28,573)	2,429	3,991		465,007	17,000	(1,496)	127	209		18,833	4.05%
Series Due May 15, 2023 (FMB) (2)	2.6000	May-13	May-23	133,333	-	4	24		133,305	3,467	-	27	166		3,660	2.75%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	606	2,655		296,739	12,375	-	29	127		12,531	4.22%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	3,604	2,870		293,526	12,000	-	163	130		12,293	4.19%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,595	4,122		344,283	12,600	-	70	180		12,850	3.73%
Series Due Sep 15, 2047 (FMB)	3.7000	Sep-17	Sep-47	600,000	-	4,818	7,088	6,744	581,350	22,200	-	199	293	279	22,971	3.95%
Series Due Mar 1, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	10,112	7,630		582,258	17,400	-	380	286		18,066	3.10%
Series Due Jun 1, 2051 (FMB)	2.6000	Jun-20	Jun-51	700,000	-	11,861	8,816		679,323	18,200	-	425	316		18,941	2.79%
Series Due Apr 1, 2031 (FMB)	2.2500	Mar-21	Apr-31	425,000	-	1,369	3,841		419,791	9,563	-	177	498		10,238	2.44%
Series Due Apr 1, 2052 (FMB)	3.2000	Mar-21	Apr-52	425,000	-	1,460	5,500		418,040	13,600	-	51	191		13,842	3.31%
Series Due May 1, 2052 (FMB)	3.3000	May-22	May-52	550,000	-	-	7,917		542,083	18,150	-	-	275		18,425	3.40%
Series Due May 1, 2033 (FMB) (1)	2.8000	May-23	May-33	283,333	-	-	4,090		279,244	7,933	-	-	428		8,361	2.99%
Series Due May 1, 2053 (FMB) (1)	3.6000	May-23	May-53	283,333	-	-	4,197		279,137	10,200	-	-	143		10,343	3.71%
Other Debt																
Right of Way Notes	var	var	var	413	-	-	-		413	-	-	-	-		-	0.00%
TOTAL DEBT				7,400,413	(23,301)	40,715	72,392	6,744	7,257,261	290,250	(1,059)	1,956	4,002	279	297,547	4.10%
Unamortized Loss on Reacquired Debt								10,487	(3,742)						700	
Fees on 5-year Credit Facility (3)									-						379	
GRAND TOTAL and COST OF DEBT									7,253,518						298,625	$\boxed{4.12\%}$

(1) NSPM 2023 issuance of $425M 10 year bond, balance is 8 of 12 months.
NSPM 2023 issuance of $425M 30 year bond, balance is 8 of 12 months.
(2) NSPM 2013 issuance of $400M 10 year bond, balance is 4 of 12 months.
(3) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.
(4) Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.
(5) Interest Expense is a Straight Interest Expense calculation.

($000's)

2024 FORECASTED LONG TERM DEBT AND COST
as of 7/30/21

Description	Coupon Rate	Issue Date	Maturity Date	Amount	Premium or Hedge Gain/(Loss)	Bond Discount	Bond Expense	LRD Expense	(3) Capital Employed	Total Bond Cost: (4) Interest Charge	Premium/ Hedge Amortization	Discount Amortization	Expense Amortization	LRD Amortization	Cost of Capital	Capital Cost %
First Mortgage Bonds																
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	74	61		249,865	17,813	-	78	63		17,954	7.19%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	213	178		149,609	9,750	-	59	49		9,858	6.59%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	178	1,112		248,710	13,125	-	16	101		13,243	5.32%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	6,471	555	1,930		403,986	25,000	546	47	163		24,664	6.11%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	-	858	1,873		347,269	21,700	-	66	145		21,911	6.31%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(1,637)	291	2,121		295,951	16,050	(107)	19	139		16,315	5.51%
Series Due August 15, 2040 (FMB)	4.8500	Aug-10	Aug-40	250,000	-	379	1,618		248,003	12,125	-	24	101		12,249	4.94%
Series Due August 15, 2042 (FMB)	3.4000	Aug-12	Aug-42	500,000	(27,073)	2,302	3,781		466,844	17,000	(1,501)	128	210		18,838	4.04%
Series Due May 15, 2044 (FMB)	4.1250	May-14	May-44	300,000	-	577	2,527		296,896	12,375	-	29	128		12,532	4.22%
Series Due Aug 15, 2045 (FMB)	4.0000	Aug-15	Aug-45	300,000	-	3,441	2,739		293,820	12,000	-	164	130		12,294	4.18%
Series Due May 15, 2046 (FMB)	3.6000	May-16	May-46	350,000	-	1,525	3,941		344,534	12,600	-	70	181		12,851	3.73%
Series Due Sep 15, 2047 (FMB)	3.7000	Sep-17	Sep-47	600,000	-	4,618	6,794	6,465	582,124	22,200	-	200	294	280	22,973	3.95%
Series Due Mar 1, 2050 (FMB)	2.9000	Sep-19	Mar-50	600,000	-	9,731	7,343		582,926	17,400	-	381	287		18,068	3.10%
Series Due Jun 1, 2051 (FMB)	2.6000	Jun-20	Jun-51	700,000	-	11,435	8,499		680,066	18,200	-	426	317		18,943	2.79%
Series Due Apr 1, 2031 (FMB)	2.2500	Mar-21	Apr-31	425,000	-	1,191	3,342		420,468	9,563	-	178	499		10,240	2.44%
Series Due Apr 1, 2052 (FMB)	3.2000	Mar-21	Apr-52	425,000	-	1,409	5,308		418,283	13,600	-	51	192		13,843	3.31%
Series Due May 1, 2052 (FMB)	3.3000	May-22	May-52	550,000	-	-	7,642		542,358	18,150	-	-	276		18,426	3.40%
Series Due May 1, 2033 (FMB)	2.8000	May-23	May-33	425,000	-	-	5,602		419,398	11,900	-	-	639		12,539	2.99%
Series Due May 1, 2053 (FMB)	3.6000	May-23	May-53	425,000	-	-	6,117		418,883	15,300	-	-	213		15,513	3.70%
Series Due May 1, 2054 (FMB) (1)	3.6000	May-24	May-54	300,000	-	-	4,443		295,557	10,800	-	-	151		10,951	3.71%
Other Debt																
Right of Way Notes	var	var	var	413	-	-	-		413	-	-	-	-		-	0.00%
TOTAL DEBT				7,850,413	(22,239)	38,777	76,970	6,465	7,705,962	306,650	(1,062)	1,935	4,277	280	314,204	4.08%
Unamortized Loss on Reacquired Debt									(3,041)						702	
Fees on 5-year Credit Facility (2)									-						379	
GRAND TOTAL and COST OF DEBT									7,702,921						315,284	4.09%

(1) NSPM 2024 issuance of $450M 30 year bond, balance is 8 of 12 months.
(2) Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.
(3) Capital Employed is based on the Premium / Discount / Expense Balances representing average declining balances. New and Maturing Debt averaged on number of months in the year.
(4) Interest Expense is a Straight Interest Expense calculation.

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
31 December 2020

Update

Rate this Research

RATINGS

Northern States Power Company (Minnesota)

Domicile	Minneapolis, Minnesota, United States
Long Term Rating	A2
Type	LT Issuer Rating
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Northern States Power Company (Minnesota)

Update to credit analysis

Summary

The credit profile of Northern States Power Company (Minnesota) (NSP-Minnesota) reflects the fully regulated nature of its vertically integrated electric and natural gas distribution operations in Minnesota (nearly 90% of its rate base), North and South Dakota (each accounts for less than 10% of its rate base). The profile reflects our view that these regulatory environments are generally credit supportive, particularly in Minnesota where it benefits from several riders as well as annual sales true-ups.

The credit assumes that the utility will continue to produce a ratio of cash flow from operations excluding changes in working capital (CFO pre-W/C) to debt at or above 22% following the Minnesota Public Utility's Commission (MPUC) recent approval of the utility's extension to its stay-out period, through 2021.

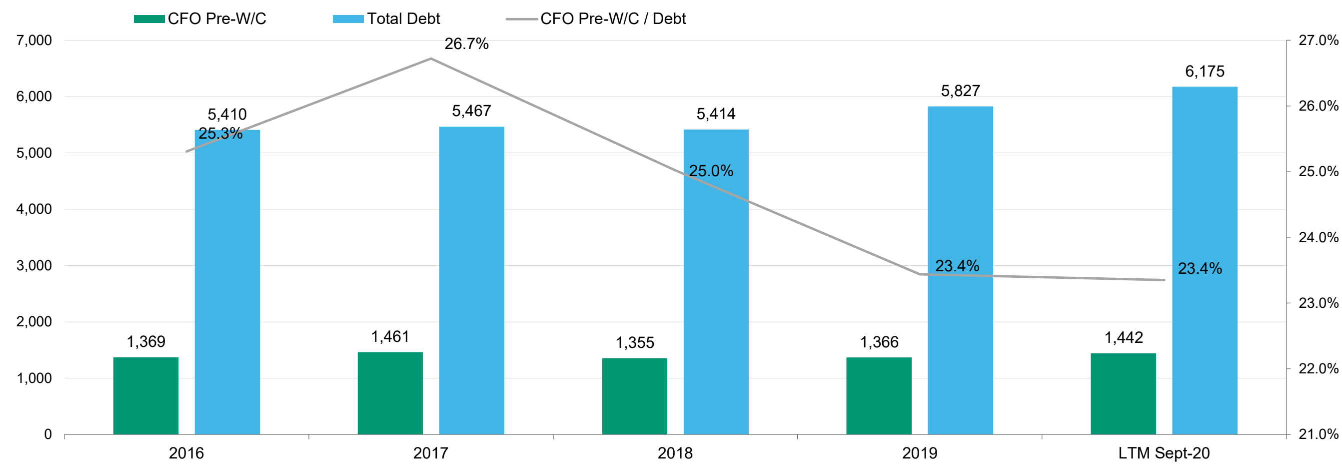
NSP-Minnesota ranks as one of the larger subsidiaries in the Xcel Energy Inc. (Xcel, Baa1 stable) family in terms of rate base (2019 estimated: 37%) as well as earnings before interest, taxes, depreciation and amortization (EBITDA) and cash flow contribution (40%-45%). The credit profile also recognizes that NSP-Minnesota's state regulators indirectly restrict dividends that the utility is allowed to upstream to parent Xcel by requiring NSP-Minnesota to maintain an equity-to-total capitalization ratio ranging between 47.1% to 57.5%.

Recent Developments

Coronavirus - The rapid spread of the coronavirus outbreak, severe global economic shock, low oil prices, and asset price volatility are creating a severe and extensive credit shock across many sectors, regions and markets. The combined credit effects of these developments are unprecedented. We regard the coronavirus outbreak as a social risk under our ESG framework, given the substantial implications for public health and safety. However, we expect the NSP-Minnesota to be relatively resilient to recessionary pressures because of its rate regulated business model and regulatory mechanisms.

Exhibit 1

Historical CFO Pre-W/C, Total Debt and CFO Pre-W/C to Debt ($ MM)



Source: Moody's Financial Metrics

Credit strengths

» Vertically integrated regulated utility operations in overall credit supportive regulatory environments

» Numerous riders and trackers that reduce regulatory lag

» Dividend distributions are subject to the commissions' indirectly imposed restrictions regarding capital structure

Credit challenges

» Some uncertainty around the utility's capex pending the approval of the Minnesota Relief and Recovery

» Credit metrics are lower than historical highs, but remain supportive of credit quality.

Rating outlook

NSP-Minnesota's stable outlook is supported by the predictable nature of the utility's operations and the expectation that the regulatory environments will remain credit supportive. The stable outlook assumes that although lower than previous highs, its key credit metrics will remain adequate for its credit, including CFO pre-W/C to debt of at least 22%. The outlook considers Xcel's group-wide O&M-cost control initiatives, overall timely recovery of costs, as well as some moderation in the utility's base case capex.

Factors that could lead to an upgrade

» While not expected in the near term, the utility's ratings could experience positive momentum if greater than anticipated regulatory relief or cost savings, or a reduction in leverage, allow it to record CFO pre-W/C to debt in the high 20% range.

Factors that could lead to a downgrade

» The ratings could be downgraded if we perceive a deterioration in the credit supportiveness of its regulatory environments, or if its credit metrics deteriorate further; specifically, downward pressure on the ratings could result if its CFO pre-W/C to debt ratio falls below 22%, for an extended period.

Key indicators

Exhibit 2
Northern States Power Company - Minnesota

	Dec-16	Dec-17	Dec-18	Dec-19	LTM Sept-20
CFO Pre-W/C + Interest / Interest	6.7x	7.0x	6.6x	6.7x	6.7x
CFO Pre-W/C / Debt	25.3%	26.7%	25.0%	23.4%	23.4%
CFO Pre-W/C – Dividends / Debt	18.0%	17.5%	16.6%	15.4%	15.4%
Debt / Capitalization	40.3%	44.0%	43.0%	42.9%	43.0%

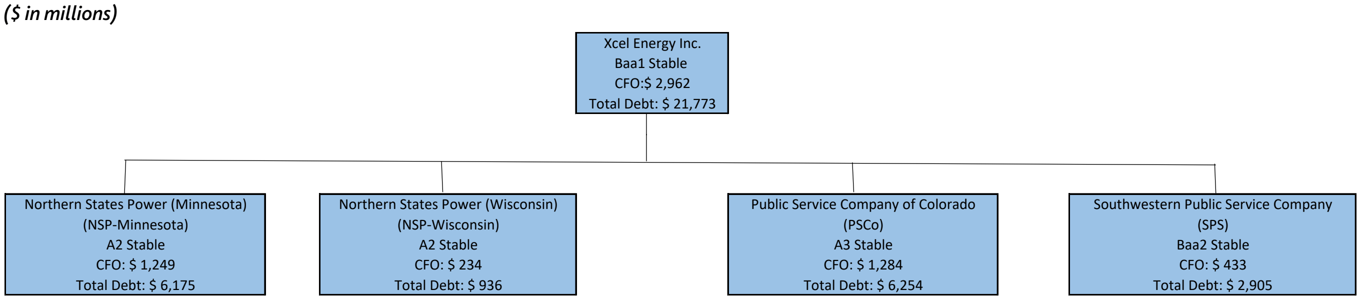
[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

NSP-Minnesota is a vertically integrated utility that provides electric services to 1.5 million customers in Minnesota, North Dakota and South Dakota as well as natural gas services to 0.5 million customers in Minnesota and North Dakota. Minnesota, mostly around Minneapolis-St. Paul, accounts for the bulk of its operations (almost 90% of revenues).

As depicted in Exhibit 3, NSP-Minnesota is the legacy subsidiary of parent Xcel Energy Inc. (Xcel, Baa1 stable), a holding company with utility operations in eight states servicing around 3.7 million electric customers and about 2.1 million natural gas customers. NSP-Minnesota is the second largest subsidiary in terms of regulated rate base (2019 year-end estimate: $11.3 billion) after Public Service Company of Colorado (PSCO, A3 stable; 2019 year-end estimate: 12.4 billion) with each contributing between 35-45% to Xcel's consolidated net income. NSP-Minnesota and its smaller neighboring sister company Northern States Power (Wisconsin) (NSP-Wisconsin, A2 stable) operate their electric production and transmission systems as an integrated system known as the NSP-System. They share the costs of operating their integrated production and transmission systems (NSP-System) according to a Federal Energy Regulatory Commission (FERC) approved Interchange Agreement (IA).

Exhibit 3
Xcel Energy Inc. Organizational Chart (LTM 3Q2020)
($ in millions)



Source: Xcel Energy Inc., Moody's Financial Metrics

Detailed credit considerations

Limited diversification benefits; bulk of operations are in Minnesota

NSP-Minnesota's credit quality reflects limited geographic diversification benefits because Minnesota accounts for the majority of its operations while North and South Dakota (electric only) each represent around 6% of the total. At the same time, the Federal Energy Regulatory Commission's (FERC) oversight of NSP-Minnesota's wholesale production (nearly 5% of the utility's 2019 total electric revenues) and transmission services modestly enhances its regulatory diversity.

Overall credit supportive regulatory environments

Riders and surcharges reduce regulatory lag

Our view of the credit supportiveness of the regulatory frameworks in the states in which NSP-Minnesota operates considers that the utility's cash flows benefit from a broad group of rider mechanisms that allow for the timely recovery of costs and investments between rate cases and the ability to implement multi-year rate plans in all three states. The utility also benefits from the ability to implement interim rates until final tariff decisions are made, automatic fuel and purchase power cost recovery mechanisms (subject to monthly adjustments) and transmission riders. These mechanisms reduce the exposure of the utility's cash flows to the impact of regulatory lag as the utility stayed out of rate cases in recent years.

Exhibit 4
Summary of key regulatory mechanisms available in NSP-Minnesota's jurisdictions

	Multi-year Rate Plans	Forward Test Year	Interim Rates	Fuel Recovery Mechanism	Renewable Rider	Transmission Rider	Distribution Recovery Mechanism	Infrastructure Rider	Pension Deferral Mechanism	Property Tax Deferral/True-up	Decoupling
NSP-M	√	√ MN & ND	√	√	√ MN & ND	√ MN & ND	√ MN	√ SD	√ MN	√ MN	√ MN

Source: Xcel Energy Inc., regulatory filings

However, the number of automatic recovery mechanisms is more extensive in Minnesota (including distribution and decoupling) followed by North Dakota. This drives our view that these regulatory frameworks are above-average in terms of credit supportiveness compared to most other states, including South Dakota. In South Dakota, rates are based on historical test periods which, along with a limited number of riders, have contributed to the utility's volatile actual return on equities (RoEs) (see Exhibit 5).

Exhibit 5
Summary of key financial parameters including authorized and actual RoEs and applicable regulatory plans

		Authorized RoE	W/A Earned RoE (actual) 2017	2018	2019	Regulatory Plan
NSP-Minnesota	Electric-Mn	9.20%	9.66%	8.88%	9.31%	Stay-out through 2021 verbally approved by the MPCU
	NG-Mn	10.09%	9.16%	9.81%	8.54%	
	Electric - ND	9.85%	10.91%	9.93%	9.86%	Filed Rate Case in 2020
	NG-ND	9.75%	8.75%	10.32%	3.74%	TCJA Settlement 2019-20
	Electric - SD	Blackbox	6.91%	6.79%	8.77%	TCJA Settlement 2019-20

Source: Xcel Energy Inc., Regulatory filings

Overall credit constructive regulatory proceedings

In Minnesota, NSP-Minnesota benefits from a decoupling mechanisms (implemented in January 2016) for electric residential end-users, as well as small commercial and industrial (C&I) customers, although their annual increases are capped at 3%. In addition, revenues from all non-decoupled electric customers are also subject to sales true-ups. These mechanism is credit supportive because it enhances the visibility of the utility's cash flows, particularly in the aftermath of the economic disruption caused by the coronavirus pandemic. Next year, the utility's rates will be adjusted to reflect both, this year's material increase in the residential customers power demand as well as the significant reduction in the C&I customers' demand. During the nine month period ended September 2020, NSP-Minnesota reported a reduction in total retail sales of nearly 3.4% (weather-adjusted: -4.2%). The increase in residential power demand (actual: +5.6%) could not fully offset the 3.4% contraction in sales to its C&I customer-class (on a weather adjusted basis: -7.5%).

This sales true-up, along with capital and property tax true-up mechanisms, were implemented as part of the utility's 2016-2019 rate plan that expired last year. These mechanisms will remain in place for at least another year following the MPUC's authorization (verbal approval in December 2020) of NSP-Minnesota's proposed stay out provision in December 2020. The extension of the mechanisms is credit positive because it reduces the utility's exposure to regulatory lag. Similar to last year, the utility also withdrew the rate case (filed in November 2020) requesting a rate increase that totaled $597 million for the 2021-2023 period. In its 2020 stay-out petition, the utility also requested authority to delay any increase to the nuclear decommissioning trust annual accrual until January 1, 2022. On a less positive note, the utility also agreed to implement an earnings sharing mechanism. According to the agreement, NSP-Minnesota will refund to customers all earnings above a RoE of 9.06% in 2021, which is consistent with the last RoE approved in a rider request, but below the 9.2% RoE authorized in its last rate case (Order in June 2017).

However, we acknowledge that this earnings test, along with the utility's agreement not to seek rate relief for incremental bad debt expenses in the aftermath of the coronavirus pandemic, and its agreement to fund $17.5 million in customer relief programs should help the utility manage its relationship with its stakeholders, a credit positive. Utilities in Minnesota are currently subject to the annual winter moratorium of shutting off residential customer service for non-payment (until April 15) which overlapped with this year's disconnection bans put in place at the onset of the pandemic. However, we believe that the impact on the utility's cash flows of foregoing this rate relief (bad debt expenses) and payment assistance will not be significant. Xcel's management recently disclosed that it estimates that the group's consolidated bad debt expenses (2019: around $55 million) will rise by around $25 million during 2020 which equals to an increase by around 50%. For NSP-Minnesota, a similar increase would result in a step-up of its reported allowance for doubtful accounts (AFDA) to around $34.5 million (year-end 2019: $23 million). However, similar to other US utilities, NSP-Minnesota's base rates include recovery of its historical write-offs, that is the annual amounts which were deemed ultimately uncollectible. This amount reduces the cash impact of its bad debt expense. As a point of reference, the utility's write-offs averaged $12.6 million or less than 1% of its reported funds from operations during the 2015-2019 period.

In North and South Dakota, in November 2020, NSP-Minnesota requested the North Dakota Public Service Commission's (NDPSC) authorization to increase its retail electric revenues by $22 million (+10.8%). It is premised on a rate base of $677 million for the 2021 test year as well as increase in its authorized RoE to 10.2% (+34 basis points) and an equity layer of 52 .5%. The utility also requested authorization to implement an interim rate increase of about $16 million in January 2021. This is the first rate case filed by the utility in ND following the expiration of the two-year rate freeze that the utility agreed to (also in South Dakota) in exchange for authority to retain the amounts due to the electric customers in 2018 and 2019 in connection to the implementation of the 2017 Tax Cuts and Jobs Act (TCJA). NSP-Minnesota was authorized to use the refundable amounts due to natural gas customers to amortize the regulatory assets related to unrecovered manufactured gas plant site expenses in Fargo. The outcome of NSP-Minnesota's ongoing rate case will be an important indication of both the utility's relationship with the NDPUC and the credit supportiveness of the ND regulatory environment. North Dakota remains one of the few jurisdictions where the regulator has not made a decision yet as to whether authorize the utilities' request to apply deferral accounting treatment to incremental costs related to the coronavirus pandemic, and record them under regulatory assets and liabilities.

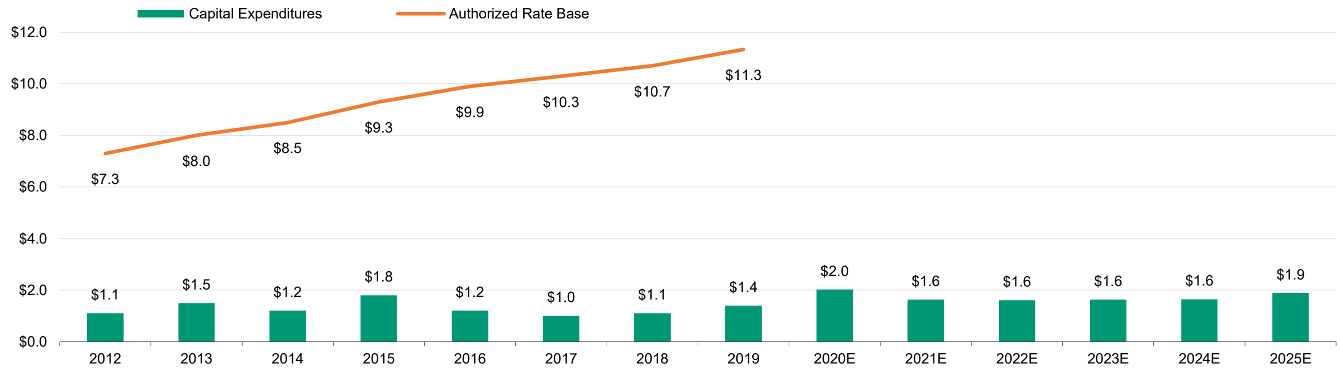
FERC - NSP-Minnesota's credit also benefits from the predictable cash flow associated with its FERC regulated transmission operations. Our view of the credit supportiveness of the FERC regulatory environment recognizes that tariffs are set on a forward-looking basis utilizing formulaic rate recovery mechanisms and true-ups (including for sales), as well as robust (60%) equity layers. NSP-Minnesota, similar to other Midcontinent Independent System Operator (MISO) transmission owners, has been involved in two Federal Power Act (FPA) Section 206 complaints filed at the FERC by customers and public groups. The complaints questioned the justness and reasonableness of the base ROE for MISO transmission owners. In May 2020, following a request to rehear its November 2019 order, the FERC issued a final resolution of a pending 206 complaint (first complaint) disputing the justness and reasonableness of the base RoE for MISO transmission owners, including NSP-Minnesota. Following additional revisions to the base RoE methodology, the May Order increased the base RoE to 10.02% (November 2019 order: 9.88%), effective as of the end of September 2016, which includes the continuation of a 0.5% RoE incentive adder. The transmission utilities are required to provide refunds, with interest, for the 15-month refund period from November 12, 2013 through February 11, 2015 and for the period from September 28, 2016 through May 21, 2020. We understand the impact of the refunds on NSP-Minnesota' cash flows is not significant. According to the May Order, the second 206 complaint (filed in February 2015) covering a statutory refund period from February 2015 to May 2016 remains dismissed.

Some uncertainty around apex program, but likely to remain moderate

Xcel has disclosed that NSP-Minnesota's capital expenditures (capex) program for the 2021-2025 period will aggregate $8.4 billion with annual investments averaging around $1.7 billion. The utility has earmarked the bulk of the investments (nearly 75%) to expand its electric transmission, distribution and generation footprint. According to this plan, the completion next year of the 300 MW Dakota Range wind project (COD: 2021) will complete its currently planned investments in renewables (capex in 2021:$295 million; afterwards: $0). Between 2019 and 2021, NSP-Minnesota will have completed five wind projects and acquired two wind farms, increasing its wind-farm capacity to nearly 2.2 GW from 840 MW at year-end 2018 (see ESG Section). These investments exceed the company's historical annual capital outlays (around $6.8 billion for the 2016-2020 period, or about $1.3 billion annually).

Exhibit 6

NSP-Minnesota's rate base and 2012-2025 historical and projected capital expenditure plan
($ in billions)



These planned expenditures exclude investments related to the Minnesota Relief and Recovery proposal.
Source: Xcel Energy Inc.

However, pending the MPCU's approval of its Minnesota Relief and Recovery (R&R) proposal, NSP-Minnesota's investments in renewables could increase by around $1.3 billion (+16%) while it would also accelerate its planned investments in the grid ($865 million). This proposal followed the MPUC's 2020 invitation to submit projects to create jobs and aid the economy in the aftermath of the pandemic outbreak. NSP-Minnesota's proposal includes the repowering of 651 MW of owned wind-projects (total capex: $750 million) as well as the construction of 460MW in solar projects (incremental capex: $650 million). In December 2020, the MPUC approved the utility's wind repowering proposal. NSP-Minnestoa requested a decision regarding the solar assets before the end of June 2021. We estimate that, including these incremental annual investments, the utility's ratio of capex to depreciation during the 2021-2025 period would still remain below 2.0x (average ratio during the 2016-last twelve month period ended September 2020: 1.7x),

We understand that, if these new renewable projects are approved and developed, NSP-Minnesota would undertake the investments but share the costs with NSP-Wisconsin through the aforementioned Interchange Agreement (IA). NSP-Minnesota operates the NSP-System while NSP-Wisconsin is responsible for around 15% of the demand related costs. Generally, the associated interchange revenues received from NSP-Wisconsin represent around 10% of NSP-Minnesota's total revenues.

Credit metrics have declined from historic highs but expected to remain supportive of credit quality

As depicted under Exhibits 1 and 2, NSP-Minnesota's credit metrics were historically very well positioned for the credit profile, including CFO pre-W/C to debt that consistently exceeded 25% during the 2015-2018 period. However, the ratio dropped to 23.4% last year largely due to the cash leakage that resulted from the implementation of the TCJA, particularly the combination of the expiration of bonus depreciation and the MPUC's order to refund $141 million to its electric and natural gas customers following the reevaluation of the accumulated deferred income tax (ADIT) at the lower corporate tax rate of 21%.

That said, we note that the ratio remained stable at 23.4% for the last twelve month period ended September 2020 while it also reported a RoE of 9.53% (GAAP) during the same period despite the economic disruption caused by the pandemic. The utility's financial ratios were aided by the aforementioned automatic recovery mechanisms and additional cost savings. During the nine month period ended September 2020, the utility reported a reduction in its operational and maintenance expenses by $20.2million (-4.5%) compared to the same period in 2019 (during financial year 2019 compared to 2018:- 1.7%). During 2020, these initiatives are largely related to lower plant generation expenses (including timing of planned maintenance and overhauls).

Going forward, we assume that automatic recovery mechanisms and additional cost savings will allow the utility to record financial metrics that will remain adequate for the credit profile. This expectation includes a ratio of CFO pre-W/C to debt of at or above 22% over the foreseeable future even if the aforementioned incremental investments associated with the Minnesota R&R program (+$1.3 billion) are approved. NSP-Minnesota's dividend distributions is subject to the utility recording an equity-to-total capitalization ratio that ranges between 47.1% and 57.1% (2010: 52.3%).

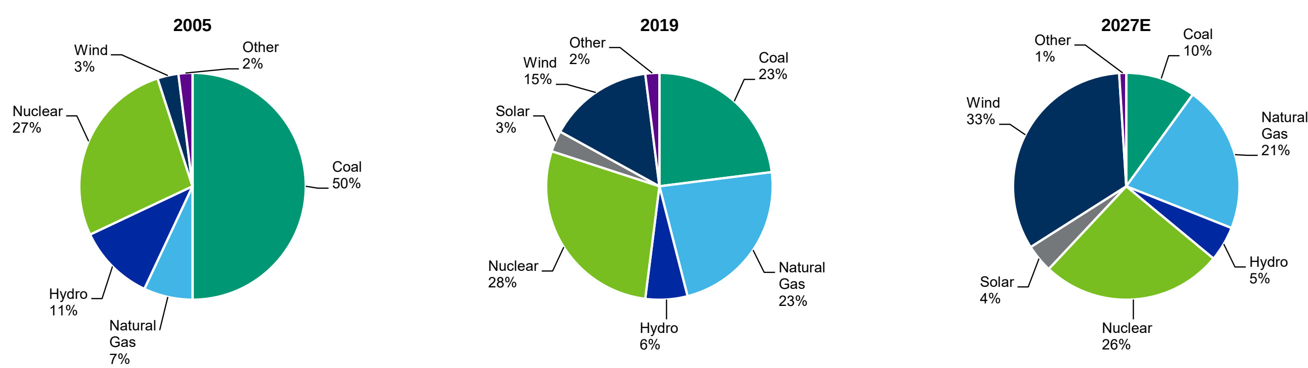
ESG considerations

Environmental considerations incorporated into our analysis of NSP-Minnesota are primarily related to carbon dioxide regulations as well as the natural gas distribution operations' clean-up expenses related to manufactured gas plants (MGP) and also methane emissions. NSP-Minnestoa's parent, Xcel, is strongly positioned for carbon transition in the regulated utility sector with strategies and plans in place that substantially mitigate its carbon transition exposure.

Environmental considerations incorporated into our credit analysis of NSP-Minnesota factors in Xcel's goal of producing 100% carbon free energy by 2050. It also considers that NSP-Minnesota aims to reduce, by 2030, carbon dioxide emissions to 80% below 2005 levels. However, this goal is pending the approval of its Resource Plan that was initially filed in July 2019 with a supplement filed in June 2020. Xcel expects during 2021.

The NSP System generates the bulk of the power requirements of NSP-Minnesota with a portion procured under Power Purchase Agreements. NSP-Minnesota's goals incorporate the output from its nuclear fleet (1,657 MW) as the utility's Resource Plan seeks to extend the life of the Monticello nuclear plant to 2040 from 2030 and to maintain operations at the Prairie Island nuclear units until 2033 and 2034 (the end of their lives). Exhibit 5 illustrates the growing contribution of renewables following the addition of the aforementioned wind-farms to the energy-mix (installed capacity: 2.2 GW; 2018: 840 MW). It also depicts Xcel's expectation that the approved retirement of NSP-Minnesota's 1,362 MW Sherco Unit 2 (2023) and Unit 1 (2026) will reduce the contribution of coal-fired facility output to the energy mix of NSP-Wisconsin and NSP-Minnesota to around 10% in 2027 (2019: 23%).

Exhibit 7
2005-2027 planned development of NSP-Minnesota's energy mix



Source: Xcel Energy Inc.

However, the contribution from coal could drop to 0% if the MPUC approves NSP Minnesota's Resource Plan for the period ending 2034. The utility also proposed the retirement of the 511 MW King facility and the 517 MW Sherco Unit 3 by 2030. We assume that, upon their retirement, the utility will be able to recover the remaining rate base of its coal-fired facilities (all more than 35 years old). We assume that this rate base is relatively small, and largely reflects environmental compliance investments.

The Resource Plan also includes the construction of the Sherco combined cycle natural gas plant (CCGT; peak investment in 2026; CoD: 2028). The plan also includes demand side Management (DSM) initiatives such as energy efficiency programs (annual savings through 2034 around 780 GWh), and 400 MW of incremental demand response by 2023 (total by 2034: over 1,500 MW). The utility has also proposed the addition of around 2,600 MW of firm peaking resources (including combustion turbine battery storage and pumped hydro) between 2031 and 2034, as well solar (3,500 MW) and wind (2,200 MW) assets. These additions will also replace wind assets that are expected to retire during that period.

The completion of the majority of NSP-Minnesota's aforementioned wind projects before year-end 2020 allow them to quality for 100% of Production Tax Credits (PTCs) while the 300 MW Dakota Range (COD: 2021) is expected to quality for 80% of PTCs. The flow back to customers of the tax benefits, along with the saved fuel costs, and the termination of PPAs (that are subject to elevated contracted prices), along with the group-wide focus on reducing O&M-expenses and credit back to customers of the tax credits (PTCs and ITCs) are key elements of the group-wide's strategy to limit the impact of the utilities' material investment on the customers' bills. As per the Resource Plan, NSP-Minnesota's goal is to keep the annual cost increases below the rate of inflation.

Social risks are primarily related to demographic and societal trends as well as customer and regulatory relations. Corporate governance considerations include financial policy and we note that a strong financial position is an important characteristic for managing environmental and social risks amid the group's significant capital expenditure program.

Liquidity analysis

Similar to its sister companies, NSP-Minnesota has its own separate committed credit facility. Following the group's amendment of the facilities, in June 2019, they are now scheduled to mature in June 2024. This facility back-stops the utility's same-sized $500 million CP-program (Prime-1). At the end of September 2020, the utility had $490 million available under this credit facility (letter of credits outstanding: $10 million) as well as $422.8 million of cash on hand. The facility provides for same day funding and borrowings are not subject to conditionality, including any MAC clause. We anticipate the utility will be able to continue to comfortably comply with the only financial covenant embedded in the facility, namely a total Debt/Capitalization ratio below 65%. As of September 2020, the ratio was 47.5% (2019: 48%). Furthermore, in March 2020, NSP-Minnesota renewed the $75 million one-year uncommitted bilateral credit agreement for an additional one-year term, which is used to support letters of credit (available at the end of September 2020: $29 million).

NSP-Minnesota also participates in a regulated money pool with its sister companies (since October 2020, including NSP-Wisconsin). As of 30 September 2020, NSP-Minnesota's $250 million borrowing limit was fully available. This money pool allows for short-term loans among those utility subsidiaries and allows for short-term loans from Xcel to the utilities. However, it does not permit loans from the utilities to Xcel. NPS-Minnesota's next debt maturity consists of $300 million first mortgage bonds (FMB) due in August 2022.

Xcel has publicly disclosed that NSP-Minnesota will issue $400 million first mortgage bonds in 2021 following the 2.60% $700 million FMB issuance completed in September 2020 (maturity: June 2051). We anticipate that the utility will fund its capital requirements in 2021, including investments (in 2021:$1.6 billion), largely with internally generated cash flows (as a point of reference, LTM September 2020: nearly $1.2 billion) and short and long-term debt financing. We also anticipate that Xcel will continue to manage NSP-Minnesota's dividend policy (LTM September 2020: $493 million) and equity contributions to the utility (LTM September 202: $423 million) so as to meet its regulatory capital structure (that is a aforementioned range of equity-to-total capitalization ratio). In January 2020, Xcel contributed $150 million across the four pension plans (NSP-Minnesota's contribution: $44 million; 2019: $47 million).

Rating methodology and scorecard factors

Moody's evaluates NSP-Minnesota's financial performance relative to the Regulated Electric and Gas Utilities rating methodology published in June 2017. As depicted in the grid below, the company's scorecard-indicated outcome based on historical as well as projected average key credit metrics is A2, the same as its assigned senior unsecured rating.

Exhibit 8

Northern States Power Company (Minnesota)

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 9/30/2020		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.9x	Aa	6x - 7x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	24.6%	A	22% - 24%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	17.1%	A	16% - 18%	A
d) Debt / Capitalization (3 Year Avg)	43.1%	A	40% - 42%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A2		A2
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		A2		A2
b) Actual Rating Assigned		A2		A2

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 9/30/2020(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
[4] Standard risk grid for financial strength.
Source: Moody's Financial Metrics

Appendix

Exhibit 9

Peer Comparison [1]

	Northern States Power Company (P)A2 (Stable)			Northern States Power Company (P)A2 (Stable)			ALLETE, Inc. Baa1 (Stable)			Otter Tail Power Company A3 (Stable)		
(In US millions)	FYE Dec-18	FYE Dec-19	LTM Sept-20	FYE Dec-18	FYE Dec-19	LTM Sept-20	FYE Dec-18	FYE Dec-19	LTM Sept-20	FYE Dec-19	FYE Dec-19	LTM Sept-20
Revenue	5,122	5,112	5,050	1,022	981	958	1,499	1,241	1,153	450	459	448
CFO Pre-W/C	1,355	1,366	1,442	213	230	228	387	335	328	111	142	156
Total Debt	5,414	5,827	6,175	908	903	936	1,703	1,806	2,201	600	686	760
CFO Pre-W/C + Interest / Interest	6.6x	6.7x	6.7x	6.2x	6.9x	6.9x	6.0x	5.7x	5.7x	4.7x	5.6x	5.7x
CFO Pre-W/C / Debt	25.0%	23.4%	23.4%	23.5%	25.4%	24.3%	22.7%	18.6%	14.9%	18.6%	20.7%	20.5%
CFO Pre-W/C – Dividends / Debt	16.6%	15.4%	15.4%	13.4%	16.1%	17.5%	16.0%	11.9%	9.2%	11.5%	14.3%	14.6%
Debt / Capitalization	43.0%	42.9%	43.0%	42.9%	41.9%	41.3%	41.8%	41.6%	45.5%	46.0%	47.3%	45.6%

Source: Moody's Financial Metrics

Exhibit 10

Cash flow and credit metrics [1]

CF Metrics	Dec-16	Dec-17	Dec-18	Dec-19	LTM Sept-20
As Adjusted					
FFO	**1,395**	**1,485**	**1,419**	**1,420**	**1,487**
+/- Other	-26	-24	-65	-55	-45
CFO Pre-WC	**1,369**	**1,461**	**1,355**	**1,366**	**1,442**
+/- ΔWC	-42	-158	159	-183	-193
WC	1,327	1,302	1,514	1,183	1,249
WC	1,369	1,461	1,355	1,366	1,442
CFO	**1,327**	**1,302**	**1,514**	**1,183**	**1,249**
- Div	396	507	456	467	493
- Capex	1,178	984	1,146	1,410	1,353
FCF	**-247**	**-188**	**-89**	**-693**	**-597**
(CFO Pre-W/C) / Debt	25.3%	26.7%	25.0%	23.4%	23.4%
(CFO Pre-W/C - Dividends) / Debt	18.0%	17.5%	16.6%	15.4%	15.4%
FFO / Debt	25.8%	27.2%	26.2%	24.4%	24.1%
RCF / Debt	18.5%	17.9%	17.8%	16.4%	16.1%
Revenue	4,900	5,102	5,122	5,112	5,050
Interest Expense	240	242	240	242	253
Net Income	490	523	476	539	591
Total Assets	17,917	18,005	18,525	19,904	21,144
Total Liabilities	12,691	12,664	13,024	13,911	14,726
Total Equity	5,226	5,341	5,500	5,993	6,418

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months.
Source: Moody's Financial Metrics

Ratings

Exhibit 11

Category	Moody's Rating
NORTHERN STATES POWER COMPANY (MINNESOTA)	
Outlook	Stable
Issuer Rating	A2
First Mortgage Bonds	Aa3
Senior Secured Shelf	(P)Aa3
Sr Unsec Bank Credit Facility	A2
Senior Unsecured Shelf	(P)A2
Commercial Paper	P-1
PARENT: XCEL ENERGY INC.	
Outlook	Stable
Issuer Rating	Baa1
Sr Unsec Bank Credit Facility	Baa1
Senior Unsecured	Baa1
Subordinate Shelf	(P)Baa2
Pref. Shelf	(P)Baa3
Commercial Paper	P-2

Source: Moody's Investors Service

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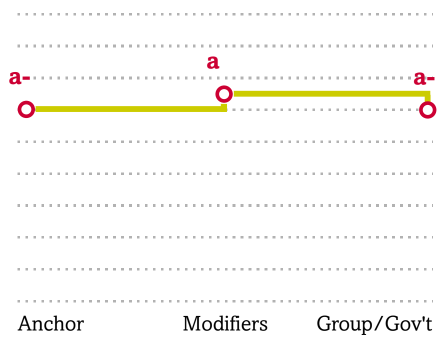
Business Risk: EXCELLENT

Vulnerable — Excellent

Financial Risk: SIGNIFICANT

Highly leveraged — Minimal



Issuer Credit Rating

A-/Stable/A-2

Credit Highlights

Overview

Key strengths	Key risks
Low-risk vertically integrated electric and natural gas utility.	Operational and environmental risks associated with nuclear and coal generation.
Large, mostly residential customer base.	Geographic diversity largely limited to Minnesota.
Steady utility operating cash flow.	Negative discretionary cash flow, indicating external funding needs.

High-level residential customer load limits revenue impact of COVID-19. Residential customers comprise about 90% of Northern States Power Co.'s (NSP's) customers and 33% of NSP's revenue, dampening weakened revenue from industrial and commercial customers after a mandated pandemic-related lockdown.

We expect the company to maintain credit measures consistent with its current rating. Our base-case scenario, with additional capital expenditure for renewable generation projects, expects NSP to maintain adjusted funds from operations (FFO) to debt in the 20%-22% range, above the midpoint of the financial risk profile benchmark range.

Efforts underway to change the generation mix toward sustainable renewable wind energy. In line with parent Xcel Energy Inc., NSP has taken steps to rebalance the generation mix with investments in wind generation projects in addition to existing wind generation capacity. The gradual change toward the corporate target of 80% carbon reduction by 2030 began in 2005.

Outlook: Stable

The stable outlook on NSP reflects that on Xcel. We base the outlook on our expectation that Xcel's management will continue to reach constructive regulatory outcomes to avoid any significant rise in business risk for the regulated utilities. Specifically, our base-case forecast includes adjusted FFO to debt of about 16% and assumes the company will continue to fund its capital investments in a balanced manner to support its capital structure.

Downside scenario

We could lower the rating on Xcel and its subsidiaries, including NSP, if Xcel's financial ratios weaken and consistently reflect adjusted FFO to debt at or below 15%. This would most likely occur if rate-case outcomes are weaker than expected and capital spending materially rises.

Upside scenario

We could raise the ratings if Xcel improves its collective ability to manage regulatory risk across its jurisdictions, resulting in a consistent improvement to its business risk. We could also raise the rating if the company's consolidated financial measures consistently exceed our baseline forecast, including adjusted FFO to debt of greater than 20%.

Our Base-Case Scenario

Assumptions

- Continued cost recovery through various regulatory mechanisms;
- Annual gross margin in the 60%-62% range;
- Annual capital spending averaging about $1.8 billion through 2022;
- Annual dividends averaging about $320 million;
- Negative discretionary cash flow indicates external funding needs; and
- All debt maturities are refinanced.

Key metrics

	2020E	2021E	2022E
Adjusted FFO to debt (%)	20.5-22.5	20-22	19-21
Adjusted debt to EBITDA (x)	3.7-4.1	3.8-4.2	4-4.4
Adjusted FFO to cash interest(x)	6.4-6.8	6.1-6.5	5.7-6.1

E--Expected. FFO--Funds from operations.

Company Description

Minneapolis-based NSP is a vertically integrated electric and natural gas distribution utility operating in Minnesota, North Dakota, and South Dakota.

Peer comparison

Table 1

Northern States Power Co.--Peer Comparison

Industry Sector: Electric

	Northern States Power Co.	Wisconsin Electric Power Co.	Consumers Energy Co.	Union Electric Co. d/b/a Ameren Missouri
Ratings as of Oct. 27, 2020	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2
	--Fiscal year ended Dec. 31, 2019			
(Mil. $)				
Revenue	5,111.8	3,496.7	6,341.5	3,243.0
EBITDA	1,866.3	1,300.4	2,246.6	1,288.0
Funds from operations (FFO)	1,524.5	688.0	1,813.6	982.3
Interest expense	357.8	221.5	340.1	221.3
Cash interest paid	237.4	566.6	301.1	204.7
Cash flow from operations	1,194.2	892.9	1,678.6	1,056.3
Capital expenditure	1,437.1	627.8	2,181.0	1,095.0
Free operating cash flow (FOCF)	(243.0)	265.1	(502.5)	(38.7)
Discretionary cash flow (DCF)	(709.6)	(94.3)	(1,094.5)	(470.2)
Cash and short-term investments	126.3	19.1	11.0	9.0
Debt	5,979.9	4,250.8	8,369.6	4,226.0
Equity	6,081.8	3,576.3	7,737.0	4,309.0
Adjusted ratios				
EBITDA margin (%)	36.5	37.2	35.4	39.7
Return on capital (%)	8.2	11.2	7.7	8.5
EBITDA interest coverage (x)	5.2	5.9	6.6	5.8
FFO cash interest coverage (x)	7.4	2.2	7.0	5.8
Debt/EBITDA (x)	3.2	3.3	3.7	3.3
FFO/debt (%)	25.5	16.2	21.7	23.2
Cash flow from operations/debt (%)	20.0	21.0	20.1	25.0
FOCF/debt (%)	(4.1)	6.2	(6.0)	(0.9)

Table 1

Northern States Power Co.--Peer Comparison (cont.)				
Industry Sector: Electric				
	Northern States Power Co.	**Wisconsin Electric Power Co.**	**Consumers Energy Co.**	**Union Electric Co. d/b/a Ameren Missouri**
DCF/debt (%)	(11.9)	(2.2)	(13.1)	(11.1)

Business Risk: Excellent

NSP's business risk profile incorporates its low-risk, rate-regulated utility operations that serve over 2 million electric and natural gas customers in Minnesota, North Dakota, and South Dakota. Although NSP operates in three states, there is limited geographic and regulatory diversity because NSP earns about 90% of its revenue in Minnesota. Revenue stability is supported with a customer base that is about 90% residential contributing about 33% to the revenues. NSP has implemented multiyear rate plans and benefits from credit-supportive infrastructure riders. As NSP's generation capacity consists of nuclear (28%) and coal-fired (23%), the higher operating risk associated with nuclear-power generation and potential environmental risks from coal generation marginally weakens the company's business risk profile.

Financial Risk: Significant

Our stand-alone financial risk profile for NSP incorporates a base-case scenario that includes adjusted FFO to debt weakening toward 20%, just above the midpoint of the benchmark range of the significant category. Supporting the financial risk profile determination is the supplemental ratio of adjusted FFO cash interest coverage in the 5.7x-6.8x range. In addition, we expect the utility's elevated capital spending, when combined with its dividend, will result in negative discretionary cash flow. To offset the negative cash flow, we expect external funding, such as debt issuances and cash injections within the Xcel Energy group. We expect debt leverage, as indicated by debt to EBITDA, to rise and remain in the 3.7x-4.4x range over the next few years. Reflecting the company's steady cash flow and rate-regulated utility operations, we base our risk assessment on our medial volatility table benchmarks. These are more relaxed benchmarks than those used for a typical corporate issuer.

NSP's financial measures in our base-case scenario will consistently be above the midpoint of benchmark range for the financial risk profile, albeit weakening over the next few years.

Financial summary

Table 2

Northern States Power Co.--Financial Summary					
Industry Sector: Electric					
	--Fiscal year ended Dec. 31--				
	2019	2018	2017	2016	2015
(Mil. $)					
Revenue	5,111.8	5,121.9	5,102.0	4,900.3	4,756.8

Table 2

Northern States Power Co.--Financial Summary (cont.)					
EBITDA	1,866.3	1,738.3	1,852.7	1,807.8	1,459.9
Funds from operations (FFO)	1,524.5	1,580.5	1,524.3	1,524.7	1,286.4
Interest expense	357.8	356.9	378.6	372.3	346.4
Cash interest paid	237.4	246.8	257.5	244.1	226.7
Cash flow from operations	1,194.2	1,477.6	1,256.1	1,290.4	1,310.8
Capital expenditure	1,437.1	1,158.8	988.5	1,186.4	1,837.7
Free operating cash flow (FOCF)	(243.0)	318.8	267.6	103.9	(526.9)
Discretionary cash flow (DCF)	(709.6)	(137.5)	(239.0)	(292.0)	(786.1)
Cash and short-term investments	126.3	50.0	43.8	52.8	42.6
Gross available cash	126.3	50.0	43.8	47.6	42.6
Debt	5,979.9	5,661.7	5,605.4	5,885.9	5,734.7
Equity	6,081.8	5,573.1	5,475.6	5,355.6	5,167.1
Adjusted ratios					
EBITDA margin (%)	36.5	33.9	36.3	36.9	30.7
Return on capital (%)	8.2	8.3	9.4	9.9	8.4
EBITDA interest coverage (x)	5.2	4.9	4.9	4.9	4.2
FFO cash interest coverage (x)	7.4	7.4	6.9	7.2	6.7
Debt/EBITDA (x)	3.2	3.3	3.0	3.3	3.9
FFO/debt (%)	25.5	27.9	27.2	25.9	22.4
Cash flow from operations/debt (%)	20.0	26.1	22.4	21.9	22.9
FOCF/debt (%)	(4.1)	5.6	4.8	1.8	(9.2)
DCF/debt (%)	(11.9)	(2.4)	(4.3)	(5.0)	(13.7)

Reconciliation

Table 3

Northern States Power Co.--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

	--12 months ended June 30, 2020--									
Northern States Power Co. reported amounts (mil. $)										
	Debt	**Shareholders' equity**	**Revenue**	**EBITDA**	**Operating income**	**Interest expense**	**S&P Global Ratings' adjusted EBITDA**	**Cash flow from operations**	**Dividends**	**Capital expenditure**
	6,202.3	6,289.8	5,006.4	1,591.1	787.8	227.9	1,825.3	1,232.2	483.1	1,435.3
S&P Global Ratings' adjustments										
Cash taxes paid	--	--	--	--	--	--	(84.8)	--	--	--
Cash interest paid	--	--	--	--	--	--	(214.1)	--	--	--
Reported lease liabilities	566.4	--	--	--	--	--	--	--	--	--
Operating leases	--	--	--	7.7	10.3	10.3	(10.3)	(2.6)	--	--
Postretirement benefit obligations/deferred compensation	157.9	--	--	--	--	--	--	--	--	--

Table 3

Northern States Power Co.--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts (cont.)										
Accessible cash and liquid investments	(784.3)	--	--	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	--	13.2	(13.2)	(13.2)	--	(13.2)
Power purchase agreements	353.2	--	--	50.8	12.7	12.7	(12.7)	38.1	--	38.1
Asset-retirement obligations	41.9	--	--	107.1	107.1	107.1	--	--	--	--
Nonoperating income (expense)	--	--	--	--	36.9	--	--	--	--	--
Debt: Other	(546.5)	--	--	--	--	--	--	--	--	--
EBITDA: Other income/(expense)	--	--	--	68.6	68.6	--	--	--	--	--
Depreciation and amortization: Other	--	--	--	--	(68.6)	--	--	--	--	--
Total adjustments	(211.4)	0.0	0.0	234.2	167.0	143.3	(335.1)	22.3	0.0	24.9
S&P Global Ratings' adjusted amounts										
	Debt	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Dividends**	**Capital expenditure**
	5,990.9	6,289.8	5,006.4	1,825.3	954.8	371.2	1,490.2	1,254.5	483.1	1,460.2

Liquidity: Adequate

We assess the company's stand-alone liquidity as adequate because we believe its liquidity sources are likely to cover uses by more than 1.1x over the next 12 months and meet cash outflows even with a 10% decline in EBITDA. The assessment also reflects our view of the company's generally prudent risk management, sound relationship with banks, and a generally satisfactory standing in credit markets.

Principal liquidity sources

- Cash and liquid investments of about $130 million
- Credit facility availability of about $800 million
- Estimated cash FFO of roughly $1.25 billion

Principal liquidity uses

- Debt maturities, including outstanding commercial paper, of about $330 million
- Capital spending of about $1.3 billion
- Dividends of about $320 million

Environmental, Social, And Governance

Governance and social factors for the company are consistent with what we see across the industry for other publicly traded utilities.

Parent Xcel's fuel mix consists of approximately 24% renewables, 13% nuclear, 33% natural gas, 26% coal, and 4% hydro and other sources. The company's reliance on coal-fired generation exposes it to the ongoing cost of operating older units in the face of disruptive technological advances and the potential for more environmental regulations requiring significant capital investments. However, the company is trying to reduce its carbon footprint; it plans to shutter upwards of 3,100 megawatts (MW) of coal-fueled generation in the U.S. and will convert roughly 1,000 MW of coal to natural gas, invest in a combined-cycle natural gas plant, invest in 3,500 MW of solar generation, and invest in 2,250 MW of wind generation. By pursuing greater renewable generation, the company is meeting customer demand for greener energy. Additionally, parent Xcel operates two nuclear plants, with one expected to remain open through 2034, that generate around 1,700 MW of power. Although carbon-free, the company's nuclear generation portfolio increases operating risk and exposes it to longer-term nuclear waste storage risks.

Group Influence

Under our group rating methodology, we consider NSP as a core subsidiary of parent Xcel, reflecting our view that NSP is highly unlikely to be sold, is integral to the overall group strategy, possesses a strong long-term commitment from senior management, and is closely linked to the parent's name and reputation. We assess NSP's issuer credit rating to be in line with Xcel's group credit profile of 'a-'.

Issue Ratings - Subordination Risk Analysis

We base the short-term rating of 'A-2' on the issuer credit rating on the company.

Issue Ratings - Recovery Analysis

NSP's first mortgage bonds benefit from a first-priority lien on substantially all the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Ratings Score Snapshot

Issuer Credit Rating

A-/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Significant

- **Cash flow/leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Strong (no impact)
- **Comparable rating analysis:** Positive (+1 notch)

Stand-alone credit profile : a

- **Group credit profile:** a-
- **Entity status within group:** Core (-1 notch from SACP)

Related Criteria

- Criteria - Corporates - General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria - Corporates - Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012

- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of December 18, 2020)*

Northern States Power Co.		
Issuer Credit Rating		A-/Stable/A-2
Commercial Paper		
Local Currency		A-2
Senior Secured		A
Issuer Credit Ratings History		
23-Jun-2010	*Foreign Currency*	A-/Stable/A-2
10-Jun-2009		BBB+/Positive/A-2
16-Oct-2007		BBB+/Stable/A-2
23-Jun-2010	*Local Currency*	A-/Stable/A-2
10-Jun-2009		BBB+/Positive/A-2
16-Oct-2007		BBB+/Stable/A-2

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

JUNE 23, 2017

INFRASTRUCTURE

MOODY'S
INVESTORS SERVICE

RATING
METHODOLOGY

Regulated Electric and Gas Utilities

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This rating methodology replaces "Regulated Electric and Gas Utilities" last revised on December 23, 2013. We have updated some outdated links and removed certain issuer-specific information.

Summary

This rating methodology explains our approach to assessing credit risk for regulated electric and gas utilities globally. This document does not include an exhaustive treatment of all factors that are reflected in our ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector.[1]

This report includes a detailed rating grid which is a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to companies in the regulated electric and gas utility industry. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary substantially. In addition, the grid in this document uses historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each company.

THIS METHODOLOGY WAS UPDATED ON AUGUST 2, 2018. WE HAVE MADE MINOR FORMATTING ADJUSTMENTS THROUGHOUT THE METHODOLOGY.

THIS RATING METHODOLOGY WAS UPDATED ON FEBRUARY 15, 2018. WE HAVE CORRECTED THE FORMATTING OF THE FACTOR 4: FINANCIAL STRENGTH TABLE ON PAGE 34.

THIS RATING METHODOLOGY WAS UPDATED ON SEPTEMBER 27, 2017. WE REMOVED A DUPLICATE FOOTNOTE THAT WAS PLACED IN THE MIDDLE OF THE TEXT ON PAGE 7.

[1] This update may not be effective in some jurisdictions until certain requirements are met.

The grid contains four key factors that are important in our assessment for ratings in the regulated electric and gas utility sector:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength

Some of these factors also encompass a number of sub-factors. There is also a notching factor for holding company structural subordination.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, corporate legal structure, governance and country related risks which are not explained in detail in this document, as well as factors that can be meaningful on a company-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex grid that might map grid-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A discussion of the key rating factors that drive ratings

» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the grid

The Appendices show the full grid (Appendix A), our approach to ratings within a utility family (Appendix B), a description of the various types of companies rated under this methodology (Appendix C), key industry issues over the intermediate term (Appendix D), regional and other considerations (Appendix E), and treatment of power purchase agreements (Appendix F).

This methodology describes the analytical framework used in determining credit ratings. In some instances our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities. A link to documents that describe our approach to such cross-sector credit rating methodological considerations can be found in the Related Research section of this report.

About the Rated Universe

The Regulated Electric and Gas Utilities rating methodology applies to rate-regulated[2] electric and gas utilities that are not Networks[3]. Regulated Electric and Gas Utilities are companies whose predominant[4] business is the sale of electricity and/or gas or related services under a rate-regulated framework, in most cases to retail customers. Also included under this methodology are rate-regulated utilities that own generating assets as any material part of their business, utilities whose charges or bills to customers include a meaningful component related to the electric or gas commodity, utilities whose rates are regulated at a sub-sovereign level (e.g. by provinces, states or municipalities), and companies providing an independent system operator function to an electric grid. Companies rated under this methodology are primarily rate-regulated monopolies or, in certain circumstances, companies that may not be outright monopolies but where government regulation effectively sets prices and limits competition.

This rating methodology covers regulated electric and gas utilities worldwide. These companies are engaged in the production, transmission, coordination, distribution and/or sale of electricity and/or natural gas, and they are either investor owned companies, commercially oriented government owned companies or, in the case of independent system operators, not-for-profit or similar entities. As detailed in Appendix C, this methodology covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution utilities with retail customers and/or sub-sovereign regulation, local gas distribution utility companies (LDCs), independent system operators, and regulated generation companies. These companies may be operating companies or holding companies.

An over-arching consideration for regulated utilities is the regulatory environment in which they operate. While regulation is also a key consideration for networks, a utility's regulatory environment is in comparison often more dynamic and more subject to political intervention. The direct relationship that a regulated utility has with the retail customer, including billing for electric or gas supply that has substantial price volatility, can lead to a more politically charged rate-setting environment. Similarly, regulation at the sub-sovereign level is often more accessible for participation by interveners, including disaffected customers and the politicians who want their votes. Our views of regulatory environments evolve over time in accordance with our observations of regulatory, political, and judicial events that affect issuers in the sector.

This methodology pertains to regulated electric and gas utilities and excludes the following types of issuers, which are covered by separate rating methodologies: Regulated Networks, Unregulated Utilities and Power Companies, Public Power Utilities, Municipal Joint Action Agencies, Electric Cooperatives, Regulated Water Companies and Natural Gas Pipelines.[5]

The Regulated Electric and Gas Utility sector is predominantly investment grade, reflecting the stability generally conferred by regulation that typically sets prices and also limits competition, such that defaults have been lower than in many other non-financial corporate sectors. However, the nature of regulation can

[2] Companies in many industries are regulated. We use the term rate-regulated to distinguish companies whose rates (by which we also mean tariffs or revenues in general) are set by regulators.

[3] Regulated Electric and Gas Networks are companies whose predominant business is purely the transmission and/or distribution of electricity and/or natural gas without involvement in the procurement or sale of electricity and/or gas; whose charges to customers thus do not include a meaningful commodity cost component; which sell mainly (or in many cases exclusively) to non-retail customers; and which are rate-regulated under a national framework.

[4] We generally consider a company to be predominantly a regulated electric and gas utility when a majority of its cash flows, prospectively and on a sustained basis, are derived from regulated electric and gas utility businesses. Since cash flows can be volatile (such that a company might have a majority of utility cash flows simply due to a cyclical downturn in its non-utility businesses), we may also consider the breakdown of assets and/or debt of a company to determine which business is predominant.

[5] A link to credit rating methodologies covering these and other sectors can be found in the Related Research section of this report.

vary significantly from jurisdiction to jurisdiction. Most issuers at the lower end of the ratings spectrum operate in challenging regulatory environments.

About this Rating Methodology

This report explains the rating methodology for regulated electric and gas utilities in six sections, which are summarized as follows:

1. Identification and Discussion of the Rating Factors in the Grid

The grid in this rating methodology focuses on four rating factors. The four factors are comprised of sub-factors that provide further detail:

Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%	Legislative and Judicial Underpinnings of the Regulatory Framework	12.5%
		Consistency and Predictability of Regulation	12.5%
Ability to Recover Costs and Earn Returns	25%	Timeliness of Recovery of Operating and Capital Costs	12.5%
		Sufficiency of Rates and Returns	12.5%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Key Financial Metrics	40%		
		CFO pre-WC + Interest / Interest	7.5%
		CFO pre-WC / Debt	15.0%
		CFO pre-WC – Dividends / Debt	10.0%
		Debt/Capitalization	7.5%
Total	100%		100%
Notching Adjustment			
Holding Company Structural Subordination			0 to -3

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

2. Measurement or Estimation of Factors in the Grid

We explain our general approach for scoring each grid factor and show the weights used in the grid. We also provide a rationale for why each of these grid components is meaningful as a credit indicator. The information used in assessing the sub-factors is generally found in or calculated from information in company financial statements, derived from other observations or estimated by our analysts.[6] All of the quantitative credit metrics incorporate Moody's standard adjustments to income statement, cash flow statement and balance sheet amounts for restructuring, impairment, off-balance sheet accounts, receivable securitization programs, under-funded pension obligations, and recurring operating leases.[7]

6 For definitions of our most common ratio terms, please see "Moody's Basic Definitions for Credit Statistics, User's Guide," a link to which may be found in the Related Research section of this report.

7 Our standard adjustments are described in "Financial Statement Adjustments in the Analysis of Non-Financial Corporations". A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) in the rating grid. However, the factors in the grid can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historic and expected future performance for periods of several years or more, or for individual twelve month periods.

3. Mapping Factors to the Rating Categories

After estimating or calculating each sub-factor, the outcomes for each of the sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, B, or Caa).

4. Assumptions, Limitations and Rating Considerations Not Included in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, some of the additional factors that are not included in the grid but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

5. Determining the Overall Grid-Indicated Rating[8]

To determine the overall grid-indicated rating, we convert each of the sub-factor ratings into a numeric value based upon the scale below.

Aaa	Aa	A	Baa	Ba	B	Caa	Ca
1	3	6	9	12	15	18	20

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-factor score. The composite weighted factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	$x < 1.5$
Aa1	$1.5 \leq x < 2.5$
Aa2	$2.5 \leq x < 3.5$
Aa3	$3.5 \leq x < 4.5$
A1	$4.5 \leq x < 5.5$
A2	$5.5 \leq x < 6.5$
A3	$6.5 \leq x < 7.5$
Baa1	$7.5 \leq x < 8.5$
Baa2	$8.5 \leq x < 9.5$
Baa3	$9.5 \leq x < 10.5$

[8] In general, the grid-indicated rating is oriented to the Corporate Family Rating (CFR) for speculative-grade issuers and the senior unsecured rating for investment-grade issuers. For issuers that benefit from ratings uplift due to parental support, government ownership or other institutional support, the grid-indicated rating is oriented to the baseline credit assessment. For an explanation of baseline credit assessment, please refer to our rating methodology on government-related issuers. Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. The documents that provide broad guidance for these notching decisions are our rating methodologies on loss given default for speculative grade non-financial companies and for aligning corporate instrument ratings based on differences in security and priority of claim. The link to these and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

For example, an issuer with a composite weighted factor score of 11.7 would have a Ba2 grid-indicated rating.

6. Appendices

The Appendices present a full grid and provide additional commentary and insights on our view of credit risks in this industry.

Discussion of the Grid Factors

Our analysis of electric and gas utilities focuses on four broad factors:

» Regulatory Framework

» Ability to Recover Costs and Earn Returns

» Diversification

» Financial Strength

There is also a notching factor for holding company structural subordination.

Factor 1: Regulatory Framework (25%)

Why It Matters

For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations. The regulatory environment is comprised of two rating factors - the Regulatory Framework and its corollary factor, the Ability to Recover Costs and Earn Returns. Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation. The Ability to Recover Costs and Earn Returns relates more directly to the actual decisions, including their timeliness and the rate-setting outcomes.

Utility rates[9] are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.

How We Assess Legislative and Judicial Underpinnings of the Regulatory Framework for the Grid

For this sub-factor, we consider the scope, clarity, transparency, supportiveness and granularity of utility legislation, decrees, and rules as they apply to the issuer. We also consider the strength of the regulator's authority over rate-making and other regulatory issues affecting the utility, the effectiveness of the judiciary or other independent body in arbitrating disputes in a disinterested manner, and whether the utility's monopoly has meaningful or growing carve-outs. In addition, we look at how well developed the framework is – both how fully fleshed out the rules and regulations are and how well tested it is – the extent to which regulatory or judicial decisions have created a body of precedent that will help determine future rate-making. Since the focus of our scoring is on each issuer, we consider how effective the utility is in navigating the regulatory framework – both the utility's ability to shape the framework and adapt to it.

A utility operating in a regulatory framework that is characterized by legislation that is credit supportive of utilities and eliminates doubt by prescribing many of the procedures that the regulators will use in determining fair rates (which legislation may show evidence of being responsive to the needs of the utility in general or specific ways), a long history of transparent rate-setting, and a judiciary that has provided ample precedent by impartially adjudicating disagreements in a manner that addresses ambiguities in the laws and rules will receive higher scores in the Legislative and Judicial Underpinnings sub-factor. A utility operating in a regulatory framework that, by statute or practice, allows the regulator to arbitrarily prevent the utility from recovering its costs or earning a reasonable return on prudently incurred investments, or where regulatory decisions may be reversed by politicians seeking to enhance their populist appeal will receive a much lower score.

In general, we view national utility regulation as being less liable to political intervention than regulation by state, provincial or municipal entities, so the very highest scoring in this sub-factor is reserved for this category. However, we acknowledge that states and provinces in some countries may be larger than small nations, such that their regulators may be equally "above-the-fray" in terms of impartial and technically-oriented rate setting, and very high scoring may be appropriate.

[9] In jurisdictions where utility revenues include material government subsidy payments, we consider utility rates to be inclusive of these payments, and we thus evaluate sub-factors 1a, 1b, 2a and 2b in light of both rates and material subsidy payments. For example, we would consider the legal and judicial underpinnings and consistency and predictability of subsidies as well as rates.

The relevant judicial system can be a major factor in the regulatory framework. This is particularly true in litigious societies like the United States, where disagreements between the utility and its state or municipal regulator may eventually be adjudicated in federal district courts or even by the US Supreme Court. In addition, bankruptcy proceedings in the US take place in federal courts, which have at times been able to impose rate settlement agreements on state or municipal regulators. As a result, the range of decisions available to state regulators may be effectively circumscribed by court precedent at the state or federal level, which we generally view as favorable for the credit- supportiveness of the regulatory framework.

Electric and gas utilities are generally presumed to have a strong monopoly that will continue into the foreseeable future, and this expectation has allowed these companies to have greater leverage than companies in other sectors with similar ratings. Thus, the existence of a monopoly in itself is unlikely to be a driver of strong scoring in this sub-factor. On the other hand, a strong challenge to the monopoly could cause lower scoring, because the utility can only recover its costs and investments and service its debt if customers purchase its services. There have some instances of incursions into utilities' monopoly, including municipalization, self-generation, distributed generation with net metering, or unauthorized use (beyond the level for which the utility receives compensation in rates). Incursions that are growing significantly or having a meaningful impact on rates for customers that remain with the utility could have a negative impact on scoring of this sub-factor and on factor 2 - Ability to Recover Costs and Earn Returns.

The scoring of this sub-factor may not be the same for every utility in a particular jurisdiction. We have observed that some utilities appear to have greater sway over the relevant utility legislation and promulgation of rules than other utilities – even those in the same jurisdiction. The content and tone of publicly filed documents and regulatory decisions sometimes indicates that the management team at one utility has better responsiveness to and credibility with its regulators or legislators than the management at another utility.

While the underpinnings to the regulatory framework tend to change relatively slowly, they do evolve, and our factor scoring will seek to reflect that evolution. For instance, a new framework will typically become tested over time as regulatory decisions are issued, or perhaps litigated, thereby setting a body of precedent. Utilities may seek changes to laws in order to permit them to securitize certain costs or collect interim rates, or a jurisdiction in which rates were previously recovered primarily in base rate proceedings may institute riders and trackers. These changes would likely impact scoring of sub-factor 2b - Timeliness of Recovery of Operating and Capital Costs, but they may also be sufficiently significant to indicate a change in the regulatory underpinnings. On the negative side, a judiciary that had formerly been independent may start to issue decisions that indicate it is conforming its decisions to the expectations of an executive branch that wants to mandate lower rates.

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

How We Assess Consistency and Predictability of Regulation for the Grid

For the Consistency and Predictability sub-factor, we consider the track record of regulatory decisions in terms of consistency, predictability and supportiveness. We evaluate the utility's interactions in the regulatory process as well as the overall stance of the regulator toward the utility.

In most jurisdictions, the laws and rules seek to make rate-setting a primarily technical process that examines costs the utility incurs and the returns on investments the utility needs to earn so it can make investments that are required to build and maintain the utility infrastructure - power plants, electric transmission and distribution systems, and/or natural gas distribution systems. When the process remains technical and transparent such that regulators can support the financial health of the utility while balancing their public duty to assure that reliable service is provided at a reasonable cost, and when the utility is able to align itself with the policy initiatives of the governing jurisdiction, the utility will receive higher scores in this sub-factor. When the process includes substantial political intervention, which could take the form of legislators or other government officials publically second- guessing regulators, dismissing regulators who have approved unpopular rate increases, or preventing the implementation of rate increases, or when regulators ignore the laws/rules to deliver an outcome that appears more politically motivated, the utility will receive lower scores in this sub-factor.

As with the prior sub-factor, we may score different utilities in the same jurisdiction differently, based on outcomes that are more or less supportive of credit quality over a period of time. We have observed that some utilities are better able to meet the expectations of their customers and regulators, whether through better service, greater reliability, more stable rates or simply more effective regulatory outreach and communication. These utilities typically receive more consistent and credit supportive outcomes, so they will score higher in this sub-factor. Conversely, if a utility has multiple rapid rate increases, chooses to submit major rate increase requests during a sensitive election cycle or a severe economic downturn, has chronic customer service issues, is viewed as frequently providing incomplete information to regulators, or is tone deaf to the priorities of regulators and politicians, it may receive less consistent and supportive outcomes and thus score lower in this sub-factor.

In scoring this sub-factor, we will primarily evaluate the actions of regulators, politicians and jurists rather than their words. Nonetheless, words matter when they are an indication of future action. We seek to differentiate between political rhetoric that is perhaps oriented toward gaining attention for the viewpoint of the speaker and rhetoric that is indicative of future actions and trends in decision- making.

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2: Ability to Recover Costs and Earn Returns (25%)

Why It Matters

This rating factor examines the ability of a utility to recover its costs and earn a return over a period of time, including during differing market and economic conditions. While the Regulatory Framework looks at the transparency and predictability of the rules that govern the decision-making process with respect to utilities, the Ability to Recover Costs and Earn Returns evaluates the regulatory elements that directly impact the ability of the utility to generate cash flow and service its debt over time. The ability to recover prudently incurred costs on a timely basis and to attract debt and equity capital are crucial credit considerations. The inability to recover costs, for instance if fuel or purchased power costs ballooned during a rate freeze period, has been one of the greatest drivers of financial stress in this sector, as well as the cause of some utility defaults. In a sector that is typically free cash flow negative (due to large capital expenditures and dividends) and that routinely needs to refinance very large maturities of long-term debt, investor concerns about a lack of timely cost recovery or the sufficiency of rates can, in an extreme scenario, strain access to capital markets and potentially lead to insolvency of the utility (as was the case when "used and useful" requirements threatened some utilities that experienced years of delay in completing nuclear power plants in the 1980s). While our scoring for the Ability to Recover Costs and Earn Returns may primarily be influenced by our assessment of the regulatory relationship, it can also be highly impacted by the management and business decisions of the utility.

How We Assess Ability to Recover Costs and Earn Returns

The timeliness and sufficiency of rates are scored as separate sub-factors; however, they are interrelated. Timeliness can have an impact on our view of what constitutes sufficient returns, because a strong assurance of timely cost recovery reduces risk. Conversely, utilities may have a strong assurance that they will earn a full return on certain deferred costs until they are able to collect them, or their generally strong returns may allow them to weather some rate lag on recovery of construction-related capital expenditures. The timeliness of cost recovery is particularly important in a period of rapidly rising costs. During the past five years, utilities have benefitted from low interest rates and generally decreasing fuel costs and purchased power costs, but these market conditions could easily reverse. For example, fuel is a large component of total costs for vertically integrated utilities and for natural gas utilities, and fuel prices are highly volatile, so the timeliness of fuel and purchased power cost recovery is especially important.

While Factors 1 and 2 are closely inter-related, scoring of these factors will not necessarily be the same. We have observed jurisdictions where the Regulatory Framework caused considerable credit concerns – perhaps it was untested or going through a transition to de-regulation, but where the track record of rate case outcomes was quite positive, leading to a higher score in the Ability to Recover Costs and Earn Returns. Conversely, there have been instances of strong Legislative and Judicial Underpinnings of the Regulatory Framework where the commission has ignored the framework (which would affect Consistency and Predictability of Regulation as well as Ability to Recover Costs and Earn Returns) or has used extraordinary measures to prevent or defer an increase that might have been justifiable from a cost perspective but would have caused rate shock.

One might surmise that Factors 2 and 4 should be strongly correlated, since a good Ability to Recover Costs and Earn Returns would normally lead to good financial metrics. However, the scoring for the Ability to Recover Costs and Earn Returns sub-factor places more emphasis on our expectation of timeliness and sufficiency of rates over time; whereas financial metrics may be impacted by one-time events, market conditions or construction cycles - trends that we believe could normalize or even reverse.

How We Assess Timeliness of Recovery of Operating and Capital Costs for the Grid

The criteria we consider include provisions and cost recovery mechanisms for operating costs, mechanisms that allow actual operating and/or capital expenditures to be trued-up periodically into rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress) as well as the process and timeframe of general tariff/base rate cases – those that are fully reviewed by the regulator, generally in a public format that includes testimony of the utility and other stakeholders and interest groups. We also look at the track record of the utility and regulator for timeliness. For instance, having a formula rate plan is positive, but if the actual process has included reviews that are delayed for long periods, it may dampen the benefit to the utility. In addition, we seek to estimate the lag between the time that a utility incurs a major construction expenditures and the time that the utility will start to recover and/or earn a return on that expenditure.

How We Assess Sufficiency of Rates and Returns for the Grid

The criteria we consider include statutory protections that assure full cost recovery and a reasonable return for the utility on its investments, the regulatory mechanisms used to determine what a reasonable return should be, and the track record of the utility in actually recovering costs and earning returns. We examine outcomes of rate cases/tariff reviews and compare them to the request submitted by the utility, to prior rate cases/tariff reviews for the same utility and to recent rate/tariff decisions for a peer group of comparable utilities. In this context, comparable utilities are typically utilities in the same or similar jurisdiction. In cases where the utility is unique or nearly unique in its jurisdiction, comparison will be made to other peers with an adjustment for local differences, including prevailing rates of interest and returns on capital, as well as the timeliness of rate-setting. We look at regulatory disallowances of costs or investments, with a focus on their financial severity and also on the reasons given by the regulator, in order to assess the likelihood that such disallowances will be repeated in the future.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward-looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward-looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.
Ba	**B**	**Caa**	
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.	

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa	
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.	

Factor 3: Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that economic cycles, material changes in a single regulatory regime or commodity price movements will have a severe impact on cash flow and credit quality of a utility. While utilities' sales volumes have lower exposure to economic recessions than many non-financial corporate issuers, some sales components, including industrial sales, are directly affected by economic trends that cause lower production and/or plant closures. In addition, economic activity plays a role in the rate of customer growth in the service territory and (absent energy efficiency and conservation) can often impact usage per customer. The economic strength or weakness of the service territory can affect the political and regulatory environment for rate increase requests by the utility. For utilities in areas prone to severe storms and other natural disasters, the utility's geographic diversity or concentration can be a key determinant for creditworthiness.

Diversity among regulatory regimes can mitigate the impact of a single unfavorable decision affecting one part of the utility's footprint.

For utilities with electric generation, fuel source diversity can mitigate the impact (to the utility and to its rate-payers) of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics. We have observed that utilities' regulatory environments are most likely to become unfavorable during periods of rapid rate increases (which are more important than absolute rate levels) and that fuel diversity leads to more stable rates over time.

For that reason, fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's ratepayers. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources during the past five years. These vulnerabilities have varied widely in different countries and have changed over time.

How We Assess Market Position for the Grid

Market position is comprised primarily of the economic diversity of the utility's service territory and the diversity of its regulatory regimes. We also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) when there are material operations in more than one area.

Economic diversity is a typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry. In our assessment, we may consider various information sources. For example, in the US, information sources on the diversity and vitality of economies of individual states and metropolitan areas may include Moody's Economy.com. We also look at the mix of the utility's sales volumes among customer types, as well as the track record of volume sales and any notable payment patterns during economic cycles. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. While the highest scores in the Market Position sub-factor are reserved for issuers regulated in multiple jurisdictions, when there is only one regulator, we make a differentiation of regimes perceived as having lower or higher volatility.

Issuers with multiple supportive regulatory jurisdictions, a balanced sales mix among residential, commercial, industrial and governmental customers in a large service territory with a robust and diverse economy will generally score higher in this sub-factor. An issuer with a small service territory economy that has a high dependence on one or two sectors, especially highly cyclical industries, will generally score lower in this sub-factor, as will issuers with meaningful exposure to economic dislocations caused by natural disasters.

For issuers that are vertically integrated utilities having a meaningful amount of generation, this sub- factor has a weighting of 5%. For electric transmission and distribution utilities without meaningful generation and for natural gas local distribution companies, this sub-factor has a weighting of 10%.

How We Assess Generation and Fuel Diversity for the Grid

Criteria include the fuel type of the issuer's generation and important power purchase agreements, the ability of the issuer economically to shift its generation and power purchases when there are changes in fuel prices, the degree to which the utility and its rate-payers are exposed to or insulated from changes in commodity prices, and exposure to Challenged Source and Threatened Sources (see the explanations for how we generally characterize these generation sources in the table below). A regulated utility's capacity mix may not in itself be an indication of fuel diversity or the ability to shift fuels, since utilities may keep old and inefficient plants (e.g., natural gas boilers) to serve peak load. For this reason, we do not incorporate set percentages reflecting an "ideal" or "sub-par" mix for capacity or even generation. In addition to looking at a utility's generation mix to evaluate fuel diversity, we consider the efficiency of the utility's plants, their placement on the regional dispatch curve, and the demonstrated ability/inability of the utility to shift its generation mix in accordance with changing commodity prices.

Issuers having a balanced mix of hydro, coal, natural gas, nuclear and renewable energy as well as low exposure to challenged and threatened sources of generation will score more highly in this sub-factor. Issuers that have concentration in one or two sources of generation, especially if they are threatened or challenged sources, will incur lower scores.

In evaluating an issuer's degree of exposure to challenged and threatened sources, we will consider not only the existence of those plants in the utility's portfolio, but also the relevant factors that will determine the impact on the utility and on its rate-payers. For instance, an issuer that has a fairly high percentage of its generation from challenged sources could be evaluated very differently if its peer utilities face the same magnitude of those issues than if its peers have no exposure to challenged or threatened sources. In evaluating threatened sources, we consider the utility's progress in its plan to replace those sources, its reserve margin, the availability of purchased power capacity in the region, and the overall impact of the replacement plan on the issuer's rates relative to its peer group. Especially if there are no peers in the same jurisdiction, we also examine the extent to which the utility's generation resources plan is aligned with the relevant government's fuel/energy policy.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5.00% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5.00% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definiitons
Market Position	5.00% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.

Generation and Fuel Diversity	5.00% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength (40%)

Why It Matters

Electric and gas utilities are regulated, asset-based businesses characterized by large investments in long-lived property, plant and equipment. Financial strength, including the ability to service debt and provide a return to shareholders, is necessary for a utility to attract capital at a reasonable cost in order to invest in its generation, transmission and distribution assets, so that the utility can fulfill its service obligations at a reasonable cost to rate-payers.

How We Assess It for the Grid

In comparison to companies in other non-financial corporate sectors, the financial statements of regulated electric and gas utilities have certain unique aspects that impact financial analysis, which is further complicated by disparate treatment of certain elements under US Generally Accepted Accounting Principles (GAAP) versus International Financial Reporting Standards (IFRS). Regulatory accounting may permit utilities to defer certain costs (thereby creating regulatory assets) that a non- utility corporate entity would have to expense. For instance, a regulated utility may be able to defer a substantial portion of costs related to recovery from a storm based on the general regulatory framework for those expenses, even if the utility does not have a specific order to collect the expenses from ratepayers over a set period of time. A regulated utility may be able to accrue and defer a return on equity (in addition to capitalizing interest) for construction-work-in-progress for an approved project based on the assumption that it will be able to collect that deferred equity return once the asset comes into service. For this reason, we focus more on a utility's cash flow than on its reported net income.

Conversely, utilities may collect certain costs in rates well ahead of the time they must be paid (for instance, pension costs), thereby creating regulatory liabilities. Many of our metrics focus on Cash Flow from Operations Before Changes in Working Capital (CFO Pre-WC) because, unlike Funds from Operations (FFO), it captures the changes in long-term regulatory assets and liabilities.

However, under IFRS the two measures are essentially the same. In general, we view changes in working capital as less important in utility financial analysis because they are often either seasonal (for example, power demand is generally greatest in the summer) or caused by changes in fuel prices that are typically a relatively automatic pass-through to the customer. We will nonetheless examine the impact of working capital changes in analyzing a utility's liquidity (see Other Rating Considerations – Liquidity).

Given the long-term nature of utility assets and the often lumpy nature of their capital expenditures, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from backward-looking measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance. Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including such items as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.

For this scoring grid, we have identified four key ratios that we consider the most consistently useful in the analysis of regulated electric and gas utilities. However, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. Our ratings consider the overall financial strength of a company, and in individual cases other financial indicators may also play an important role.

CFO Pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage

The cash flow interest coverage ratio is an indicator for a utility's ability to cover the cost of its borrowed capital. The numerator in the ratio calculation is the sum of CFO Pre-WC and interest expense, and the denominator is interest expense.

CFO Pre-Working Capital / Debt

This important metric is an indicator for the cash generating ability of a utility compared to its total debt. The numerator in the ratio calculation is CFO Pre-WC, and the denominator is total debt.

CFO Pre-Working Capital Minus Dividends / Debt

This ratio is an indicator for financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial, quasi- permanent outflows that can affect the ability of a utility to cover its debt obligations, and this ratio can also provide insight into the financial policies of a utility or utility holding company. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. The numerator of this ratio is CFO Pre-WC minus dividends, and the denominator is total debt.

Debt/Capitalization

This ratio is a traditional measure of balance sheet leverage. The numerator is total debt and the denominator is total capitalization. All of our ratios are calculated in accordance with our standard adjustments[10], but we note that our definition of total capitalization includes deferred taxes in addition to total debt, preferred stock, other hybrid securities, and common equity. Since the presence or absence of deferred taxes is a function of national tax policy, comparing utilities using this ratio may be more meaningful among utilities in the same country or in countries with similar tax policies. High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in bank credit facilities or other financing agreements[11]. A high ratio may result from a regulatory framework that does not permit a robust cushion of equity in the capital structure, or from a material write-off of an asset, which may not have impacted current period cash flows but could affect future period cash flows relative to debt.

There are two sets of thresholds for three of these ratios based on the level of the issuer's business risk – the Standard Grid and the Lower Business Risk (LBR) Grid. In our view, the different types of utility entities covered under this methodology (as described in Appendix E) have different levels of business risk.

Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.

Other types of utilities may have lower business risk, such that we believe that they are most appropriately assessed using the LBR Grid, due to factors that could include a generally greater transfer of risk to customers, very strong insulation from exposure to commodity price movements, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural

10 In certain circumstances, analysts may also apply specific adjustments.

11 We also examine debt/capitalization ratios as defined in applicable covenants (which typically exclude deferred taxes from capitalization) relative to the covenant threshold level.

disasters. For instance, we tend to view many US natural gas local distribution companies (LDCs) and certain US electric transmission and distribution companies (T&Ds, which lack generation but generally retain some procurement responsibilities for customers), as typically having a lower business risk profile than their vertically integrated peers. In cases of T&Ds that we do not view as having materially lower risk than their vertically integrated peers, we will apply the Standard grid. This could result from a regulatory framework that exposes them to energy supply risk, large capital expenditures for required maintenance or upgrades, a heightened degree of exposure to catastrophic storm damage, or increased regulatory scrutiny due to poor reliability, or other considerations. The Standard Grid will also apply to LDCs that in our view do not have materially lower risk; for instance, due to their ownership of high pressure pipes or older systems requiring extensive gas main replacements, where gas commodity costs are not fully recovered in a reasonably contemporaneous manner, or where the LDC is not well insulated from declining volumes.

The four key ratios, their weighting in the grid, and the Standard and LBR scoring thresholds are detailed in the following table.

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.50%		≥ 8.0x	6.0x - 8.0x	4.5x - 6.0x	3.0x - 4.5x	2.0x - 3.0x	1.0x - 2.0x	< 1.0x
CFO pre-WC / Debt	15.00%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10.00%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.50%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Notching for Structural Subordination of Holding Companies

Why It Matters

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries that are structured as advances, debt, or even hybrid securities.

Most HoldCos present their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and grid scoring is thus based on consolidated ratios. However, HoldCo creditors typically have a secondary claim on the group's cash flows and assets after OpCo creditors. We refer to this as structural subordination, because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and non-utility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors. By contrast, the debt of the HoldCo is typically serviced primarily by dividends that are upstreamed by the OpCos[12]. Under normal circumstances, these dividends are made from net income, after payment of the OpCo's interest and preferred dividends. In most non- financial corporate sectors where cash often moves freely between the entities in a single issuer family, this distinction may have less of an impact. However, in the regulated utility sector, barriers to movement of cash among companies in the corporate family can be much more restrictive, depending on the regulatory framework. These barriers can lead to significantly different probabilities of default for HoldCos and OpCos. Structural subordination also affects loss given default. Under most default[13] scenarios, an OpCo's creditors will be satisfied from the value residing at that OpCo before any of the OpCo's assets can be used to satisfy claims of the HoldCo's creditors. The prevalence of debt issuance at the OpCo level is another reason that structural subordination is usually a more serious concern in the utility sector than for investment grade issuers in other non-financial corporate sectors.

The grids for factors 1-4 are primarily oriented to OpCos (and to some degree for HoldCos with minimal current structural subordination; for example, there is no current structural subordination to debt at the operating company if all of the utility family's debt and preferred stock is issued at the HoldCo level, although there is structural subordination to other liabilities at the OpCo level). The additional risk from structural subordination is addressed via a notching adjustment to bring grid outcomes (on average) closer to the actual ratings of HoldCos.

How We Assess It

Grid-indicated ratings of holding companies may be notched down based on structural subordination. The risk factors and mitigants that impact structural subordination are varied and can be present in different combinations, such that a formulaic approach is not practical and case-by-case analyst judgment of the interaction of all pertinent factors that may increase or decrease its importance to the credit risk of an issuer are essential.

Some of the potentially pertinent factors that could increase the degree and/or impact of structural subordination include the following:

» Regulatory or other barriers to cash movement from OpCos to HoldCo

» Specific ring-fencing provisions

» Strict financial covenants at the OpCo level

» Higher leverage at the OpCo level

» Higher leverage at the HoldCo level[14]

» Significant dividend limitations or potential limitations at an important OpCo

» HoldCo exposure to subsidiaries with high business risk or volatile cash flows

Strained liquidity at the HoldCo level

» The group's investment program is primarily in businesses that are higher risk or new to the group

Some of the potentially mitigating factors that could decrease the degree and/or impact of structural subordination include the following:

12 The HoldCo and OpCo may also have intercompany agreements, including tax sharing agreements, that can be another source of cash to the HoldCo.

13 Actual priority in a default scenario will be determined by many factors, including the corporate and bankruptcy laws of the jurisdiction, the asset value of each OpCo, specific financing terms, inter-relationships among members of the family, etc.

14 While higher leverage at the HoldCo does not increase structural subordination per se, it exacerbates the impact of any structural subordination that exists

- » Substantial diversity in cash flows from a variety of utility OpCos
- » Meaningful dividends to HoldCo from unlevered utility OpCos
- » Dependable, meaningful dividends to HoldCo from non-utility OpCos
- » The group's investment program is primarily in strong utility businesses
- » Inter-company guarantees - however, in many jurisdictions the value of an upstream guarantee may be limited by certain factors, including by the value that the OpCo received in exchange for granting the guarantee

Notching for structural subordination within the grid may range from 0 to negative 3 notches. Instances of extreme structural subordination are relatively rare, so the grid convention does not accommodate wider differences, although in the instances where we believe it is present, actual ratings do reflect the full impact of structural subordination.

A related issue is the relationship of ratings within a utility family with multiple operating companies, and sometimes intermediate holding companies. Some of the key issues are the same, such as the relative amounts of debt at the holding company level compared to the operating company level (or at one OpCo relative to another), and the degree to which operating companies have credit insulation due to regulation or other protective factors. Appendix B has additional insights on ratings within a utility family.

Rating Methodology Assumptions, Limitations, and Other Rating Considerations

The grid in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that might enable the grid to map more closely to actual ratings. Accordingly, the four rating factors and the notching factor in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used in the grid in this document is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we can't disclose. In other cases, we estimate future results based upon past performance, industry trends, competitor actions or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, industry competition, disruptive technology, regulatory and legal actions.

Key rating assumptions that apply in this sector include our view that sovereign credit risk is strongly correlated with that of other domestic issuers, that legal priority of claim affects average recovery on different classes of debt, sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that lack of access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology grid, we did not explicitly include certain important factors that are common to all companies in any industry such as the quality and experience of management, assessments of corporate governance and the quality of financial reporting and information disclosure. Therefore ranking these factors by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, exposure to uncertain licensing regimes and possible government interference in some countries.

Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible precisely to express these in the rating methodology grid without making the grid excessively complex and significantly less transparent.

Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk. However, two identical companies might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liquidity position.

Other Rating Considerations

We consider other factors in addition to those discussed in this report, but in most cases understanding the considerations discussed herein should enable a good approximation of our view on the credit quality of companies in the regulated electric and gas utilities sector. Ratings consider our assessment of the quality of management, corporate governance, financial controls, liquidity management, event risk and seasonality. The analysis of these factors remains an integral part of our rating process.

Liquidity and Access to Capital Markets

Liquidity analysis is a key element in the financial analysis of electric and gas utilities, and it encompasses a company's ability to generate cash from internal sources as well as the availability of external sources of financing to supplement these internal sources. Liquidity and access to financing are of particular importance in this sector. Utility assets can often have a very long useful life- 30, 40 or even 60 years is not uncommon, as well as high price tags. Partly as a result of construction cycles, the utility sector has experienced prolonged periods of negative free cash flow – essentially, the sum of its dividends and its capital expenditures for maintenance and growth of its infrastructure frequently exceeds cash from operations, such that a portion of capital expenditures must routinely be debt financed. Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility. Substantial portions of capex are non-discretionary (for example, maintenance, adding customers to the network, or meeting environmental mandates); however, utilities were swift to cut or defer discretionary spending during the 2007-2009 recession. Dividends represent a quasi-permanent outlay, since utilities typically only rarely will cut their dividend. Liquidity is also important to meet maturing obligations, which often occur in large chunks, and to meet collateral calls under any hedging agreements.

Due to the importance of liquidity, incorporating it as a factor with a fixed weighting in the grid would suggest an importance level that is often far different from the actual weight in the rating. In normal circumstances most companies in the sector have good access to liquidity. The industry generally requires, and for the most part has, large, syndicated, multi-year committed credit facilities. In addition, utilities have demonstrated strong access to capital markets, even under difficult conditions. As a result, liquidity generally has not been an issue for most utilities and a utility with very strong liquidity may not warrant a rating distinction compared to a utility with strong liquidity. However, when there is weakness in liquidity or liquidity management, it can be the dominant consideration for ratings.

Our assessment of liquidity for regulated utilities involves an analysis of total sources and uses of cash over the next 12 months or more, as is done for all corporates. Using our financial projections of the utility and our analysis of its available sources of liquidity (including an assessment of the quality and reliability of alternate liquidity such as committed credit facilities), we evaluate how its projected sources of cash (cash from operations, cash on hand and existing committed multi-year credit facilities) compare to its projected uses (including all or most capital expenditures, dividends, maturities of short and long-term debt, our projection of potential liquidity calls on financial hedges, and important issuer-specific items such as special tax payments). We assume no access to capital markets or additional liquidity sources, no renewal of existing credit facilities, and no cut to dividends. We examine a company's liquidity profile under this scenario, its ability to make adjustments to improve its liquidity position, and any dependence on liquidity sources with lower quality and reliability.

Management Quality and Financial Policy

The quality of management is an important factor supporting the credit strength of a regulated utility or utility holding company. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and in evaluating management performance relative to performance of competitors and our projections. A record of consistency provides us with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its stated plans and guidelines.

We also assess financial policy (including dividend policy and planned capital expenditures) and how management balances the potentially competing interests of shareholders, fixed income investors and other stakeholders. Dividends and discretionary capital expenditures are the two primary components over which management has the greatest control in the short term. For holding companies, we consider the extent to which management is willing stretch its payout ratio (through aggressive increases or delays in needed decreases) in order to satisfy common shareholders. For a utility that is a subsidiary of a parent company with several utility subsidiaries, dividends to the parent may be more volatile depending on the cash generation and cash needs of that utility, because parents typically want to assure that each utility maintains the regulatory debt/equity ratio on which its rates have been set. The effect we have observed is that utility subsidiaries often pay higher dividends when they have lower capital needs and lower dividends when they have higher capital expenditures or other cash needs. Any dividend policy that cuts into the regulatory debt/equity ratio is a material credit negative.

Size – Natural Disasters, Customer Concentration and Construction Risks

The size and scale of a regulated utility has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. While size brings certain economies of scale that can somewhat affect the utility's cost structure and competitiveness, rates are more heavily impacted by costs related to fuel and fixed assets. Particularly in the US, we have not observed material differences in the success of utilities' regulatory outreach based on their size. Smaller utilities have sometimes been better able to focus their attention on meeting the expectations of a single regulator than their multi-state peers.

However, size can be a very important factor in our assessment of certain risks that impact ratings, including exposure to natural disasters, customer concentration (primarily to industrial customers in a single sector) and construction risks associated with large projects. While the grid attempts to incorporate the first two of these into Factor 3, for some issuers these considerations may be sufficiently important that the rating reflects a greater weight for these risks. While construction projects always carry the risk of cost over-runs and delays, these risks are materially heightened for projects that are very large relative to the size of the utility.

Interaction of Utility Ratings with Government Policies and Sovereign Ratings

Compared to most industrial sectors, regulated utilities are more likely to be impacted by government actions. Credit impacts can occur directly through rate regulation, and indirectly through energy, environmental and tax policies. Government actions affect fuel prices, the mix of generating plants, the certainty and timing of revenues and costs, and the likelihood that regulated utilities will experience financial stress. While our evolving view of the impact of such policies and the general economic and financial climate is reflected in ratings for each utility, some considerations do not lend themselves to incorporation in a simple ratings grid.[15]

Diversified Operations at the Utility

A small number of regulated utilities have diversified operations that are segments within the utility company, as opposed to the more common practice of housing such operations in one or more separate affiliates. In general, we will seek to evaluate the other businesses that are material in accordance with the appropriate methodology and the rating will reflect considerations from such methodologies. There may be analytical limitations in evaluating the utility and non-utility businesses when segment financial results are not fully broken out and these may be addressed through estimation based on available information. Since regulated utilities are a relatively low risk business compared to other corporate sectors, in most cases diversified non-utility operations increase the business risk profile of a utility. Reflecting this tendency, we note that assigned ratings are typically lower than grid- indicated ratings for such companies.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events include mergers and acquisitions, asset sales, spin-offs, capital restructuring programs, litigation and shareholder distributions.

Corporate Governance

Among the areas of focus in corporate governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, and ownership structure.

Investment and Acquisition Strategy

In our credit assessment we take into consideration management's investment strategy. Investment strategy is benchmarked with that of the other companies in the rated universe to further verify its consistency. Acquisitions can strengthen a company's business. Our assessment of a company's tolerance for acquisitions at a given rating level takes into consideration (1) management's risk appetite, including the likelihood of further acquisitions over the medium term; (2) share buy-back activity; (3) the company's commitment to specific leverage targets; and (4) the volatility of the underlying businesses, as well as that of the business acquired. Ratings can often hold after acquisitions even if leverage temporarily climbs above normally acceptable ranges. However, this depends on (1) the strategic fit; (2) pro-forma

[15] See also the cross-sector methodology "How Sovereign Credit Quality May Affect Other Ratings." A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

capitalization/leverage following an acquisition; and (3) our confidence that credit metrics will be restored in a relatively short timeframe.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. Such accuracy is only possible when companies have sufficient internal controls, including centralized operations, the proper tone at the top and consistency in accounting policies and procedures.

Weaknesses in the overall financial reporting processes, financial statement restatements or delays in regulatory filings can be indications of a potential breakdown in internal controls.

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward- looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor- unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward -looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward- looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non- refundable interim rates) can be collected, and permit inclusion of important forward -looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate- payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de- activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.5%		≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
CFO pre-WC / Debt	15%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.5%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Appendix B: Approach to Ratings within a Utility Family

Typical Composition of a Utility Family

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. Financing of these entities varies by region, in part due to the regulatory framework. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries or minority interests in other companies. However, in certain cases there may be material operations at the HoldCo level. Financing can occur primarily at the OpCo level, primarily at the HoldCo level, or at both HoldCo and OpCos in varying proportions. When a HoldCo has multiple utility OpCos, they will often be located in different regulatory jurisdictions. A HoldCo may have both levered and unlevered OpCos.

General Approach to a Utility Family

In our analysis, we generally consider the stand-alone credit profile of an OpCo and the credit profile of its ultimate parent HoldCo (and any intermediate HoldCos), as well as the profile of the family as a whole, while acknowledging that these elements can have cross-family credit implications in varying degrees, principally based on the regulatory framework of the OpCos and the financing model (which has often developed in response to the regulatory framework).

In addition to considering individual OpCos under this (or another applicable) methodology, we typically[16] approach a HoldCo rating by assessing the qualitative and quantitative factors in this methodology for the consolidated entity and each of its utility subsidiaries. Ratings of individual entities in the issuer family may be pulled up or down based on the interrelationships among the companies in the family and their relative credit strength.

In considering how closely aligned or how differentiated ratings should be among members of a utility family, we assess a variety of factors, including:

» Regulatory or other barriers to cash movement among OpCos and from OpCos to HoldCo

» Differentiation of the regulatory frameworks of the various OpCos

» Specific ring-fencing provisions at particular OpCos

» Financing arrangements – for instance, each OpCo may have its own financing arrangements, or the sole liquidity facility may be at the parent; there may be a liquidity pool among certain but not all members of the family; certain members of the family may better be able to withstand a temporary hiatus of external liquidity or access to capital markets

» Financial covenants and the extent to which an Event of Default by one OpCo limits availability of liquidity to another member of the family

» The extent to which higher leverage at one entity increases default risk for other members of the family

» An entity's exposure to or insulation from an affiliate with high business risk

» Structural features or other limitations in financing agreements that restrict movements of funds, investments, provision of guarantees or collateral, etc.

» The relative size and financial significance of any particular OpCo to the HoldCo and the family

16 See paragraph at the end of this section for approaches to Hybrid HoldCos.

See also those factors noted in Notching for Structural Subordination of Holding Companies.

Our approach to a Hybrid HoldCo (see definition in Appendix C) depends in part on the importance of its non-utility operations and the availability of information on individual businesses. If the businesses are material and their individual results are fully broken out in financial disclosures, we may be able to assess each material business individually by reference to the relevant Moody's methodologies to arrive at a composite assessment for the combined businesses. If non-utility operations are material but are not broken out in financial disclosures, we may look at the consolidated entity under more than one methodology. When non-utility operations are less material but could still impact the overall credit profile, the difference in business risks and our estimation of their impact on financial performance will be qualitatively incorporated in the rating.

Higher Barriers to Cash Movement with Financing Predominantly at the OpCos

Where higher barriers to cash movement exist on an OpCo or OpCos due the regulatory framework or debt structural features, ratings among family members are likely to be more differentiated. For instance, for utility families with OpCos in the US, where regulatory barriers to free cash movement are relatively high, greater importance is generally placed on the stand-alone credit profile of the OpCo.

Our observation of major defaults and bankruptcies in the US sector generally corroborates a view that regulation creates a degree of separateness of default probability. For instance, Portland General Electric (Baa1 RUR-up) did not default on its securities, even though its then-parent Enron Corp. entered bankruptcy proceedings. When Entergy New Orleans (Ba2 stable) entered into bankruptcy, the ratings of its affiliates and parent Entergy Corporation (Baa3 stable) were unaffected. PG&E Corporation (Baa1 stable) did not enter bankruptcy proceedings despite bankruptcies of two major subsidiaries - Pacific Gas & Electric Company (A3 stable) in 2001 and National Energy Group in 2003.

The degree of separateness may be greater or smaller and is assessed on a case by case basis, because situational considerations are important. One area we consider is financing arrangements. For instance, there will tend to be greater differentiation if each member of a family has its own bank credit facilities and difficulties experienced by one entity would not trigger events of default for other entities. While the existence of a money pool might appear to reduce separateness between the participants, there may be regulatory barriers within money pools that preserve separateness. For instance, non-utility entities may have access to the pool only as a borrower, only as a lender, and even the utility entities may have regulatory limits on their borrowings from the pool or their credit exposures to other pool members. If the only source of external liquidity for a money pool is borrowings by the HoldCo under its bank credit facilities, there would be less separateness, especially if the utilities were expected to depend on that liquidity source. However, the ability of an OpCo to finance itself by accessing capital markets must also be considered. Inter-company tax agreements can also have an impact on our view of how separate the risks of default are.

For a HoldCo, the greater the regulatory, economic, and geographic diversity of its OpCos, the greater its potential separation from the default probability of any individual subsidiary. Conversely, if a HoldCo's actions have made it clear that the HoldCo will provide support for an OpCo encountering some financial stress (for instance, due to delays and/or cost over-runs on a major construction project), we would be likely to perceive less separateness.

Even where high barriers to cash movement exist, onerous leverage at a parent company may not only give rise to greater notching for structural subordination at the parent, it may also pressure an OpCo's rating, especially when there is a clear dependence on an OpCo's cash flow to service parent debt.

While most of the regulatory barriers to cash movement are very real, they are not absolute. Furthermore, while it is not usually in the interest of an insolvent parent or its creditors to bring an operating utility into a bankruptcy proceeding, such an occurrence is not impossible.

The greatest separateness occurs where strong regulatory insulation is supplemented by effective ring-fencing provisions that fully separate the management and operations of the OpCo from the rest of the family and limit the parent's ability to cause the OpCo to commence bankruptcy proceedings as well as limiting dividends and cash transfers. Typically, most entities in US utility families (including HoldCos and OpCos) are rated within 3 notches of each other. However, it is possible for the HoldCo and OpCos in a family to have much wider notching due to the combination of regulatory imperatives and strong ring-fencing that includes a significant minority shareholder who must agree to important corporate decisions, including a voluntary bankruptcy filing.

Lower Barriers to Cash Movement with Financing Predominantly at the OpCos

Our approach to rating issuers within a family where there are lower regulatory barriers to movement of cash from OpCos to HoldCos (e.g., many parts of Asia and Europe) places greater emphasis on the credit profile of the consolidated group. Individual OpCos are considered based on their individual characteristics and their importance to the family, and their assigned ratings are typically banded closely around the consolidated credit profile of the group due to the expectation that cash will transit relatively freely among family entities.

Some utilities may have OpCos in jurisdictions where cash movement among certain family members is more restricted by the regulatory framework, while cash movement from and/or among OpCos in other jurisdictions is less restricted. In these situations, OpCos with more restrictions may vary more widely from the consolidated credit profile while those with fewer restrictions may be more tightly banded around the other entities in the corporate family group.

Appendix C: Brief Descriptions of the Types of Companies Rated Under This Methodology

The following describes the principal categories of companies rated under this methodology:

Vertically Integrated Utility: Vertically integrated utilities are regulated electric or combination utilities (see below) that own generation, distribution and (in most cases) electric transmission assets. Vertically integrated utilities are generally engaged in all aspects of the electricity business. They build power plants, procure fuel, generate power, build and maintain the electric grid that delivers power from a group of power plants to end-users (including high and low voltage lines, transformers and substations), and generally meet all of the electric needs of the customers in a specific geographic area (also called a service territory). The rates or tariffs for all of these monopolistic activities are set by the relevant regulatory authority.

Transmission & Distribution Utility: Transmission & Distribution utilities (T&Ds) typically operate in deregulated markets where generation is provided under a competitive framework. T&Ds own and operate the electric grid that transmits and/or distributes electricity within a specific state or region.

T&Ds provide electrical transportation and distribution services to carry electricity from power plants and transmission lines to retail, commercial, and industrial customers. T&Ds are typically responsible for billing customers for electric delivery and/or supply, and most have an obligation to provide a standard supply or provider-of-last-resort (POLR) service to customers that have not switched to a competitive supplier. These factors distinguish T&Ds from Networks, whose customers are retail electric suppliers and/or other electricity companies. In a smaller number of cases, T&Ds rated under this methodology may not have an obligation to provide POLR services, but are regulated in sub- sovereign jurisdictions. The rates or tariffs for these monopolistic T&D activities are set by the relevant regulatory authority.

Local Gas Distribution Company: Distribution is the final step in delivering natural gas to customers. While some large industrial, commercial, and electric generation customers receive natural gas directly from high capacity pipelines that carry gas from gas producing basins to areas where gas is consumed, most other users receive natural gas from their local gas utility, also called a local distribution company (LDC). LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area. Specifically, LDCs typically transport natural gas from delivery points located on large-diameter pipelines (that usually operate at fairly high pressure) to households and businesses through thousands of miles of small-diameter distribution pipe (that usually operate at fairly low pressure). LDCs are typically responsible for billing customers for gas delivery and/or supply, and most also have the responsibility to procure gas for at least some of their customers, although in some markets gas supply to all customers is on a competitive basis. These factors distinguish LDCs from gas networks, whose customers are retail gas suppliers and/or other natural gas companies. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Integrated Gas Utility: Integrated gas regulated utilities are regulated utilities that deliver gas to all end users in a particular service territory by sourcing the commodity; operating transport infrastructure that often combines high pressure pipelines with low pressure distribution systems and, in some cases, gas storage, re-gasification or other related facilities; and performing other supply-related activities, such as customer billing and metering. The rates or tariffs for the totality of these activities are set by the relevant regulatory authority. Many integrated gas utilities are national in scope.

Combination Utility: Combination utilities are those that combine an LDC or Integrated Gas Utility with either a vertically integrated utility or a T&D utility. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Regulated Generation Utility: Regulated generation utilities (Regulated Gencos) are utilities that almost exclusively have generation assets, but their activities are generally regulated like those of vertically integrated utilities. In the US, this means that the purchasers of their output (typically other investor-owned, municipal or cooperative utilities) pay a regulated rate based on the total allowed costs of the Regulated Genco, including a return on equity based on a capital structure designated by the regulator (primarily FERC). Companies that have been included in this group include certain generation companies (including in Korea and China) that are not rate regulated in the usual sense of recovering costs plus a regulated rate of return on either equity or asset value. Instead, we have looked at a combination of governmental action with respect to setting feed-in tariffs and directives on how much generation will be built (or not built) in combination with a generally high degree of government ownership, and we have concluded that these companies are currently best rated under this methodology. Future evolution in our view of the operating and/or regulatory environment of these companies could lead us to conclude that they may be more appropriately rated under a related methodology (for example, Unregulated Utilities and Power Companies).

Independent System Operator: An Independent System Operator (ISO) is an organization formed in certain regional electricity markets to act as the sole chief coordinator of an electric grid. In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system to assure that electric supply and demand are balanced at all times, and, to the extent possible, that electric demand is met with the lowest-cost sources. ISOs seek to assure adequate transmission and generation resources, usually by identifying new transmission needs and planning for a generation reserve margin above expected peak demand. In regions where generation is competitive, they also seek to establish rules that foster a fair and open marketplace, and they may conduct price-setting auctions for energy and/or capacity. The generation resources that an ISO coordinates may belong to vertically integrated utilities or to independent power producers. ISOs may not be rate-regulated in the traditional sense, but fall under governmental oversight. All participants in the regional grid are required to pay a fee or tariff (often volumetric) to the ISO that is designed to recover its costs, including costs of investment in systems and equipment needed to fulfill their function. ISOs may be for profit or not-for-profit entities.

In the US, most ISOs were formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), but the ISO that operates solely in Texas falls under state jurisdiction. Some US ISOs also perform certain additional functions such that they are designated as Regional Transmission Organizations (or RTOs).

Transmission-Only Utility: Transmission-only utilities are solely focused on owning and operating transmission assets. The transmission lines these utilities own are typically high-voltage and allow energy producers to transport electric power over long distances from where it is generated (or received) to the transmission or distribution system of a T&D or vertically integrated utility. Unlike most of the other utilities rated under this methodology, transmission-only utilities primarily provide services to other utilities and ISOs. Transmission-only utilities in most parts of the world other than the US have been rated under the Regulated Networks methodology.

Utility Holding Company (Utility HoldCo): As detailed in Appendix B, regulated electric and gas utilities are often part of corporate families under a parent holding company. The operating subsidiaries of Utility HoldCos are overwhelmingly regulated electric and gas utilities.

Hybrid Holding Company (Hybrid HoldCo): Some utility families contain a mix of regulated electric and gas utilities and other types of companies, but the regulated electric and gas utilities represent the majority of the consolidated cash flows, assets and debt. The parent company is thus a Hybrid HoldCo.

Appendix D: Key Industry Issues Over the Intermediate Term

Political and Regulatory Issues

As highly regulated monopolistic entities, regulated utilities continually face political and regulatory risk, and managing these risks through effective outreach to key customers as well as key political and regulatory decision-makers is, or at least should be, a core competency of companies in this sector. However, larger waves of change in the political, regulatory or economic environment have the potential to cause substantial changes in the level of risk experienced by utilities and their investors in somewhat unpredictable ways.

One of the more universal risks faced by utilities currently is the compression of allowed returns. A long period of globally low interest rates, held down by monetary stimulus policies, has generally benefitted utilities, since reductions in allowed returns have been slower than reductions in incurred capital costs. Essentially all regulated utilities face a ratcheting down of allowed and/or earned returns. More difficult to predict is how regulators will respond when monetary stimulus reverses, and how well utilities will fare when fixed income investors require higher interest rates and equity investors require higher total returns and growth prospects.

The following global snapshot highlights that regulatory frameworks evolve over time. On an overall basis in the US over the past several years, we have noted some incremental positive regulatory trends, including greater use of formula rates, trackers and riders, and (primarily for natural gas utilities) de-coupling of returns from volumetric sales. In Canada, the framework has historically been viewed as predictable and stable, which has helped offset somewhat lower levels of equity in the capital structure, but the compression of returns has been relatively steep in recent years. In Japan, the regulatory authorities are working through the challenges presented by the decision to shut down virtually all of the country's nuclear generation capacity, leading to uncertainty regarding the extent to which increased costs will be reflected in rate increases sufficient to permit returns on capital to return to prior levels. China's regulatory framework has continued to evolve, with fairly low transparency and some time-to-time shifts in favored versus less-favored generation sources balanced by an overall state policy of assuring sustainability of the sector, adequate supply of electricity and affordability to the general public. Singapore and Hong Kong have fairly well developed and supportive regulatory frameworks despite a trend towards lower returns, whereas Malaysia, Korea and Thailand have been moving towards a more transparent regulatory framework. The Philippines is in the process of deregulating its power market, while Indian power utilities continue to grapple with structural challenges. In Latin America, there is a wide dispersion among frameworks, ranging from the more stable, long established and predictable framework in Chile to the decidedly unpredictable framework in Argentina. Generally, as Latin American economies have evolved to more stable economic policies, regulatory frameworks for utilities have also shown greater stability and predictability.

All of the other issues discussed in this section have a regulatory/political component, either as the driver of change or in reaction to changes in economic environments and market factors.

Economic and Financial Market Conditions

As regulated monopolies, electric and gas utilities have generally been quite resistant to unsettled economic and financial market conditions for several reasons. Unlike many companies that face direct market-based competition, their rates do not decrease when demand decreases. The elasticity of demand for electricity and gas is much lower than for most products in the consumer economy.

When financial markets are volatile, utilities often have greater capital market access than industrial companies in competitive sectors, as was the case in the 2007-2009 recession. However, regulated electric and gas utilities are by no means immune to a protracted or severe recession.

Severe economic malaise can negatively affect utility credit profiles in several ways. Falling demand for electricity or natural gas may negatively impact margins and debt service protection measures, especially when rates are designed such that a substantial portion of fixed costs is in theory recovered through volumetric charges. The decrease in demand in the 2007-2009 recession was notable in comparison to prior recessions, especially in the residential sector. Poor economic conditions can make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, recessions can coincide with a lack of confidence in the utility sector that impacts access to capital markets for a period of time. For instance, in the Great Depression and (to a lesser extent) in the 2001 recession, access for some issuers was curtailed due to the sector's generally higher leverage than other corporate sectors, combined with a concerns over a lack of transparency in financial reporting.

Fuel Price Volatility and the Global Impact of Shale Gas

The ability of most utilities to pass through their fuel costs to end users may insulate a utility from exposure to price volatility of these fuels, but it does not insulate consumers. Consumers and regulators complained vociferously about utility rates during the run-up in hydro-carbon prices in 2005-2008 (oil, natural gas and, to a lesser extent, coal). The steep decline in US natural gas prices since 2009, caused in large part by the development of shale gas and shale oil resources, has been a material benefit to US utilities, because many have been able to pass through substantial base rate increases during a period when all-in rates were declining. Shale hydro-carbons have also had a positive impact, albeit one that is less immediate and direct, on non-US utilities. In much of the eastern hemisphere, natural gas prices under long-term contracts have generally been tied to oil prices, but utilities and other industrial users have started to have some success in negotiating to de-link natural gas from oil. In addition, increasing US production of oil has had a noticeable impact on world oil prices, generally benefitting oil and gas users.

Not all utilities will benefit equally. Utilities that have locked in natural gas under high-priced long- term contracts that they cannot re-negotiate are negatively impacted if they cannot pass through their full contracted cost of gas, or if the high costs cause customer dissatisfaction and regulatory backlash. Utilities with large coal fleets or utilities constructing nuclear power plants may also face negative impacts on their regulatory environment, since their customers will benefit less from lower natural gas prices.

Distributed Generation Versus the Central Station Paradigm

The regulation and the financing of electric utilities are based on the premise that the current model under which electricity is generated and distributed to customers will continue essentially unchanged for many decades to come. This model, called the central station paradigm (because electricity is generated in large, centrally located plants and distributed to a large number of customers, who may in fact be hundreds of miles away), has been in place since the early part of the 20th century. The model has worked because the economies of scale inherent to very large power plants has more than offset the cost and inefficiency (through power losses) inherent to maintaining a grid for transmitting and distributing electricity to end users.

Despite rate structures that only allow recovery of invested capital over many decades (up to 60 years), utilities can attract capital because investors assume that rates will continue to be collected for at least that long a period. Regulators and politicians assume that taxes and regulatory charges levied on electricity usage will be paid by a broad swath of residences and businesses and will not materially discourage usage of electricity in a way that would decrease the amount of taxes collected. A corollary assumption is that the number of customers taking electricity from the system during that period will continue to be high enough such that rates will be reasonable and generally more attractive than other alternatives. In the event that consumers were to switch en masse to alternate sources of generating or receiving power (for instance distributed generation), rates for remaining customers would either not cover the utility's costs, or rates would need to be increased so much that more customers may be incentivized to leave the system. This scenario has been experienced in the regulated US copper wire telephone business, where rates have increased quite dramatically for users who have not switched to digital or wireless telephone service. While this scenario continues to be unlikely for the electricity sector, distributed generation, especially from solar panels, has made inroads in certain regions.

Distributed generation is any retail-scale generation, differentiated from self-generation, which generally describes a large industrial plant that builds its own reasonably large conventional power plant to meet its own needs. While some residential property owners that install distributed generation may choose to sever their connection to the local utility, most choose to remain connected, generating power into the grid when it is both feasible and economic to do so, and taking power from the grid at other times. Distributed generation is currently concentrated in roof-top photovoltaic solar panels, which have benefitted from varying levels of tax incentives in different jurisdictions.

Regulatory treatment has also varied, but some rate structures that seek to incentivize distributed renewable energy are decidedly credit negative for utilities, in particular net metering.

Under net metering, a customer receives a credit from the utility for all of its generation at the full (or nearly full) retail rate and pays only for power taken, also at the retail rate, resulting in a materially reduced monthly bill relative to a customer with no distributed generation. The distributed generation customer has no obligation to generate any particular amount of power, so the utility must stand ready to generate and deliver that customer's full power needs at all times. Since most utility costs, including the fixed costs of financing and maintaining generation and delivery systems, are currently collected through volumetric rates, a customer owning distributed generation effectively transfers a portion of the utility's costs of serving that customer to other customers with higher net usage, notably to customers that do not own distributed generation. The higher costs may incentivize more customers to install solar panels, thereby shifting the utility's fixed costs to an even smaller group of rate-payers. California is an example of a state employing net solar metering in its rate structure, whereas in New Jersey, which has the second largest residential solar program in the US, utilities buy power at a price closer to their blended cost of generation, which is much lower than the retail rate.

To date, solar generation and net metering have not had a material credit impact on any utilities, but ratings could be negatively impacted if the programs were to grow and if rate structures were not amended so that each customer's monthly bill more closely approximated the cost of serving that customer.

In our current view, the possibility that there will be a widespread movement of electric utility customers to sever themselves from the grid is remote. However, we acknowledge that new technologies, such as the development of commercially viable fuel cells and/or distributed electric storage, could disrupt materially the central station paradigm and the credit quality of the utility sector.

Nuclear Issues

Utilities with nuclear generation face unique safety, regulatory, and operational issues. The nuclear disaster at Fukushima Daiichi had a severely negative credit impact on its owner, Tokyo Electric Power Company, Incorporated, as well as all the nuclear utilities in the country. Japan previously generated about 30% of its power from 50 reactors, but all are currently either idled or shut down, and utilities in the country face materially higher costs of replacement power, a credit negative.

Fukushima Daiichi also had global consequences. Germany's response was to require that all nuclear power plants in the country be shut by 2022. Switzerland opted for a phase-out by 2031. (Most European nuclear plants are owned by companies rated under other the Unregulated Utilities and Power Companies methodology.) Even in countries where the regulatory response was more moderate, increased regulatory scrutiny has raised operating costs, a credit negative, especially in the US, where low natural gas prices have rendered certain primarily smaller nuclear plants uneconomic. Nonetheless, we view robust and independent nuclear safety regulation as a credit-positive for the industry.

Other general issues for nuclear operators include higher costs and lower reliability related to the increasing age of the fleet. In 2013, Duke Energy Florida, Inc. decided to shut permanently Crystal River Unit 3 after it determined that a de-lamination (or separation) in the concrete of the outer wall of the containment building was uneconomic to repair. San Onofre Nuclear Generating Station was closed permanently in 2013 after its owners, including Southern California Edison Company (A3, RUR-up) and San Diego Gas & Electric Company (A2, RUR-up), decided not to pursue a re-start in light of operating defects in two steam generators that had been replaced in 2010 and 2011.

Korea Hydro and Nuclear Power Company Limited and its parent, Korea Electric Power Corporation, faced a scandal related to alleged corruption and acceptance of falsified safety documents provided by its parts suppliers for nuclear plants. Korean prosecutors' widening probe into KHNP's use of substandard parts at many of its 23 nuclear power plants caused three plants to be shut down temporarily.

Appendix E: Regional and Other Considerations

Notching Considerations for US First Mortgage Bonds

In most regions, our approach to notching between different debt classes of the same regulated utility issuer follows the guidance in the publication "Updated Summary Guidance for Notching Bonds, Preferred Stocks and Hybrid Securities of Corporate Issuers," including a one notch differential between senior secured and senior unsecured debt.[17] However, in most cases we have two notches between the first mortgage bonds and senior unsecured debt of regulated electric and gas utilities in the US.

Wider notching differentials between debt classes may also be appropriate in speculative grade. Additional insights for speculative grade issuers are provided in the publication "Loss Given Default for Speculative-Grade Companies."[18]

First mortgage bond holders in the US generally benefit from a first lien on most of the fixed assets used to provide utility service, including such assets as generating stations, transmission lines, distribution lines, switching stations and substations, and gas distribution facilities, as well as a lien on franchise agreements. In our view, the critical nature of these assets to the issuers and to the communities they serve has been a major factor that has led to very high recovery rates for this class of debt in situations of default, thereby justifying a two notch uplift. The combination of the breadth of assets pledged and the bankruptcy-tested recovery experience has been unique to the US.

In some cases, there is only a one notch differential between US first mortgage bonds and the senior unsecured rating. For instance, this is likely when the pledged property is not considered critical infrastructure for the region, or if the mortgage is materially weakened by carve-outs, lien releases or similar creditor-unfriendly terms.

Securitization

The use of securitization, a financing technique utilizing a discrete revenue stream (typically related to recovery of specifically defined expenses) that is dedicated to servicing specific securitization debt, has primarily been used in the US, where it has been quite pervasive in the past two decades. The first generation of securitization bonds were primarily related to recovery of the negative difference between the market value of utilities' generation assets and their book value when certain states switched to competitive electric supply markets and utilities sold their generation (so-called stranded costs). This technique was then used for significant storm costs (especially hurricanes) and was eventually broadened to include environmental related expenditures, deferred fuel costs, or even deferred miscellaneous expenses. States that have implemented securitization frameworks include Arkansas, California, Connecticut, Illinois, Louisiana, Maryland, Massachusetts, Mississippi, New Hampshire, New Jersey, Ohio, Pennsylvania, Texas and West Virginia. In its simplest form, a securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitization is typically underpinned by specific legislation to segregate the securitization revenues from the utility's revenues to assure their continued collection, and the details of the enabling legislation may vary from state to state. The utility benefits from the securitization because it receives an immediate source of cash (although it gives up the opportunity to earn a return on the corresponding asset), and ratepayers benefit because the cost of the securitized debt is

17 A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.
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lower than the utility's cost of debt and much lower than its all-in cost of capital, which reduces the revenue requirement associated with the cost recovery.

In the presentation of US securitization debt in published financial ratios, we make our own assessment of the appropriate credit representation but in most cases follows the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which in turn considers the terms of enabling legislation. As a result, accounting treatment may vary. In most states utilities have been required to consolidate securitization debt under GAAP, even though it is technically non- recourse.

In general, we view securitization debt of utilities as being on-credit debt, in part because the rates associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, we seek to adjust the company's ratios by including the securitization debt and related revenues for our analysis. Where the securitized debt is on balance sheet, our credit analysis also considers the significance of ratios that exclude securitization debt and related revenues. Since securitization debt amortizes mortgage-style, including it makes ratios look worse in early years (when most of the revenue collected goes to pay interest) and better in later years (when most of the revenue collected goes to pay principal).

Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership have dominated the credit profiles of utilities in Asia Pacific (excluding Japan), generally leading to ratings that are a number of notches above the Baseline Credit Assessment. Regulated electric and gas utilities with significant government ownership are rated using this methodology in conjunction with the Joint Default Analysis approach in our methodology for Government-Related Issuers.[19]

Support system for large corporate entities in Japan can provide ratings uplift, with limits

Our ratings for large corporate entities in Japan reflect the unique nature of the country's support system, and they are higher than they would otherwise be if such support were disregarded. This is reflected in the tendency for ratings of Japanese utilities to be higher than their grid implied ratings. However, even for large prominent companies, our ratings consider that support will not be endless and is less likely to be provided when a company has questionable viability rather than being in need of temporary liquidity assistance.

[19] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Appendix F: Treatment of Power Purchase Agreements ("PPAs")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, to fix the cost of power, or to comply with regulatory mandates regarding power sourcing, including renewable portfolio standards. While we regard PPAs that reduce operating or financial risk as a credit positive, some aspects of PPAs may negatively affect the credit of utilities. The most conservative treatment would be to treat a PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover the IPP's debt service and are made irrespective of whether the utility calls on the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also typically be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus we analyze them as PPAs.

PPAs are recognized qualitatively to be a future use of cash whether or not they are treated as debt-like obligations in financial ratios

The starting point of our analysis is the issuer's audited financial statements – we consider whether the utility's accountants determine that the PPA should be treated as a debt equivalent, a capitalized lease, an operating lease, or in some other manner. PPAs have a wide variety of operational and financial terms, and it is our understanding that accountants are required to have a very granular view into the particular contractual arrangements in order to account for these PPAs in compliance with applicable accounting rules and standards. However, accounting treatment for PPAs may not be entirely consistent across US GAAP, IFRS or other accounting frameworks. In addition, we may consider that factors not incorporated into the accounting treatment may be relevant (which may include the scale of PPA payments, their regulatory treatment including cost recovery mechanisms, or other factors that create financial or operational risk for the utility that is greater, in our estimation, than the benefits received). When the accounting treatment of a PPA is a debt or lease equivalent (such that it is reported on the balance sheet, or disclosed as an operating lease and thus included in our adjusted debt calculation), we generally do not make adjustments to remove the PPA from the balance sheet.

However, in relevant circumstances we consider making adjustments that impute a debt equivalent to PPAs that are off-balance sheet for accounting purposes.

Regardless of whether we consider that a PPA warrants or does not warrant treatment as a debt obligation, we assess the totality of the impact of the PPA on the issuer's probability of default. Costs of a PPA that cannot be recovered in retail rates creates material risk, especially if they also cannot be recovered through market sales of power.

Additional considerations for PPAs

PPAs have a wide variety of financial and regulatory characteristics, and each particular circumstance may be treated differently by Moody's. Factors which determine where on the continuum we treat a particular PPA include the following:

» Risk management: An overarching principle is that PPAs have normally been used by utilities as a risk management tool and we recognize that this is the fundamental reason for their existence. Thus, we will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.

» Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly we regard these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive or if regulatory support for cost recovery deteriorates, the ability to pass through costs may decrease and, as circumstances change, our treatment of PPA obligations will alter accordingly.

» Price considerations: The price of power paid by a utility under a PPA can be substantially above or below the market price of electricity. A below-market price will motivate the utility to purchase power from the IPP in excess of its retail requirements, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or at an above-market price may suffer a financial burden if they do not get full recovery in retail rates. We will focus particularly on PPAs that have mark-to-market losses, which typically indicates that they have a material impact on the utility's cash flow.

» Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. We may determine that all of a utility's PPAs represent excess capacity, or that a portion of PPAs are needed for the utility's supply obligations plus a normal reserve margin, while the remaining portion represents excess capacity. In the latter case, we may impute debt to specific PPAs that are excess or take a proportional approach to all of the utility's PPAs.

» Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. We will examine on a case-by case basis the relative credit risk associated with PPAs in comparison to plant ownership.

» Purchase requirements: Some PPAs are structured with either options or requirements to purchase the asset at the end of the PPA term. If the utility has an economically meaningful requirement to purchase, we would most likely consider it to be a debt obligation. In most such cases, the obligation would already receive on-balance sheet treatment under relevant accounting standards.

» Default provisions: In most cases, the remedies for default under a PPA do not include acceleration of amounts due, and in many cases PPAs would not be considered as debt in a bankruptcy scenario and could potentially be cancelled. Thus, PPAs may not materially increase Loss Given Default for the utility. In addition, PPAs are not typically considered debt for cross- default provisions under a utility's debt and liquidity arrangements. However, the existence of non-standard default provisions that are debt-like would have a large impact on our treatment of a PPA. In addition, payments due under PPAs are senior unsecured obligations, and any inability of the utility to make them materially increases default risk.

Each of these factors will be considered by our analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

Methods for estimating a liability amount for PPAs

According to the weighting and importance of the PPA to each utility and the level of disclosure, we may approximate a debt obligation equivalent for PPAs using one or more of the methods discussed below. In each case we look holistically at the PPA's credit impact on the utility, including the ability to pass through costs and curtail payments, the materiality of the PPA obligation to the overall business risk and cash flows of the utility, operational constraints that the PPA imposes, the maturity of the PPA obligation, the impact of purchased power on market-based power sales (if any) that the utility will engage in, and our view of future market conditions and volatility.

» Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, we may view the PPA as being most akin to an operating cost. Provided that the accounting treatment for the PPA is, in this circumstance, off-balance sheet, we will most likely make no adjustment to bring the obligation onto the utility's balance sheet.

» Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot otherwise be quantified otherwise due to limited information.

» Net Present Value: Where the analyst has sufficient information, we may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be our estimate of the cost of capital of the utility.

» Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.

» Mark-to-Market: In situations in which we believe that the PPA prices exceed the market price and thus will create an ongoing liability for the utility, we may use a net mark-to-market method, in which the NPV of the utility's future out-of-the-money net payments will be added to its total debt obligations.

» Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. If the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

If we have determined to impute debt to a PPA for which the accounting treatment is not on-balance sheet, we will in some circumstances use more than one method to estimate the debt equivalent obligations imposed by the PPA, and compare results. If circumstances (including regulatory treatment or market conditions) change over time, the approach that is used may also vary.

Moody's Related Research

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related sector and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

Please refer to Moody's Rating Symbols & Definitions, which is available here, for further information. Definitions of Moody's most common ratio terms can be found in "Moody's Basic Definitions for Credit Statistics, User's Guide", accessible via this link.

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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

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