BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION FOR: (1) REVISION OF ITS RETAIL RATES UNDER ADVICE NOTICE NO. 282; (2) AUTHORIZATION AND APPROVAL TO SHORTEN THE SERVICE LIFE OF AND ABANDON ITS TOLK GENERATING STATION UNITS; AND (3) OTHER RELATED RELIEF, **SOUTHWESTERN PUBLIC SERVICE COMPANY,** **APPLICANT.**	**)**	**CASE NO. 19-00170-UT**

DIRECT TESTIMONY

of

SARAH W. SOONG

on behalf of

SOUTHWESTERN PUBLIC SERVICE COMPANY

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	**Meaning**
Base Period	April 1, 2018 through March 31, 2019
CCR	Corporate Credit Rating
CFO	Cash from Operations
Commission	New Mexico Public Regulation Commission
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
FFO	Funds from Operations
Fitch	Fitch Ratings
Moody's	Moody's Investors Service
Op Co's	Northern States Power Company, a Minnesota corporation ("NSPM"); Northern States Power Company, a Wisconsin corporation; Public Service Company of Colorado ("PSCo") and SPS
RFP	Rate Filing Package
ROE	Return on Equity
S&P	Standard & Poor's
SPS	Southwestern Public Service Company, a New Mexico corporation
Test Year	Historical Test Year Period consisting of the Base Period and further incorporating all proper adjustments and capital additions
WACC	Weighted Average Cost of Capital

Acronym/Defined Term	**Meaning**
Xcel Energy	Xcel Energy Inc.

LIST OF ATTACHMENTS

<u>Attachment</u>	**<u>Description</u>**
SWS-10	S&P February 8, 2019: Global Market Intelligence: RRA Regulatory Focus - State Regulatory Evaluations (*Non-native format*)
SWS-11	Scotiabank Indicative New Issue Spreads May 31, 2019 (*Non-native format*)

Case No. 19-00170-UT
Direct Testimony
of
Sarah W. Soong

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Sarah W. Soong. My business address is 401 Nicollet Mall, Minneapolis, Minnesota 55401.

Q. On whose behalf are you testifying in this proceeding?

A. I am filing testimony on behalf of Southwestern Public Service Company, a New Mexico corporation ("SPS") and wholly-owned electric utility subsidiary of Xcel Energy Inc. ("Xcel Energy").

Q. By whom are you employed and in what position?

A. I am employed by Xcel Energy Services Inc. as Vice President and Treasurer.

Q. Please briefly outline your responsibilities as Vice President and Treasurer.

A. As Vice President and Treasurer, 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, and treasury services and financial policies. A description of my qualifications, duties, and responsibilities is included in this testimony as Attachment SWS-1.

Q. Have you previously provided testimony to any regulatory commission?

A. Yes. I provided testimony on financial integrity, cost of debt, and capital structure before the Colorado Public Utility Commission in the Public Service Company of Colorado's ("PSCo") steam and electric base rate cases, Case Nos. 19AL-0063ST and 19AL-0268E.

II. ASSIGNMENT AND SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. What is the purpose of your testimony in this proceeding?

A. My testimony supports SPS's weighted average cost of capital ("WACC") during the Base Period[1] at 7.28%, and for the Test Year[2] at 7.68%. I further demonstrate that a reasonable capital structure for SPS consists of 54.77% equity and 45.23% debt. SPS's proposed equity ratio of 54.77% is the same as the Base Period at March 31, 2019. The Test Year capital structure includes the proposed return on equity ("ROE") of 10.35% as supported by SPS witness Ann E. Bulkley in this proceeding. In addition, my testimony will:

- Discuss financial integrity, its importance to SPS and its stakeholders, and the need for SPS to demonstrate stable overall financial health in order to access the market in varied market conditions and raise debt capital for utility expenditures at low costs;
- Discuss the criteria that the credit rating agencies use to measure financial integrity;
- Provide a current assessment of SPS's financial integrity and describe the impact that regulatory decisions, changes in cash flow, and the timely recovery of prudent utility costs have on SPS's financial integrity;

[1] Base Period is the twelve month period April 1, 2018 through March 31, 2019

[2] The Test Year is the Historical Test Year Period consisting of the Base Period and further incorporating all proper adjustments and capital additions.

- Request that the Commission remove its restriction capping SPS's actual capital structure at 55% equity;

- Present and support the use of actual capital structure, which consists of 54.77% equity and 45.23% long-term debt, as of the end of the Base Period; and

- Present and support SPS's Base Period and Test Year cost of long-term debt, which were 4.51% and 4.44%, respectively.

Q. Are you sponsoring any attachments as part of your direct testimony?

A. Yes, I am sponsoring the following attachments:

- Attachment SWS-1, which is a description of my qualifications and responsibilities;

- Attachment SWS-2, which is a Moody's publication entitled Ratings Action: Moody's changes Xcel Energy's outlook to negative; downgrades Southwestern Public Service ratings to Baa2 with stable outlook;

- Attachment SWS-3, which is a Moody's Investors Service ("Moody's") publication entitled Regulated Electric and Gas Utilities;

- Attachment SWS-4, which is a Standard & Poor's ("S&P") publication entitled Key Credit Factors for the Regulated Utilities Industry;

- Attachment SWS-5, which is a description of the major credit rating agencies' credit ratings;

- Attachment SWS-6, which is an S&P publication entitled Ratios and Adjustment;

- Attachment SWS-7, which is a Fitch publication entitled FitchRatings: Corporates-SPS;

- Attachment SWS-8, which is an S&P publication entitled RRA Financial Focus-Xcel Energy;

- Attachment SWS-9, which is an S&P Global Market Intelligence publication entitled New Mexico Public Regulation Commission;

- Attachment SWS-10, which is an S&P Global Market Intelligence publication entitled RRA Regulatory Focus – State Regulatory Evaluations; and

- Attachment SWS-11 Scotiabank Indicative New Issue Spreads May 31, 2019.

In addition, I sponsor or co-sponsor the Rate Filing Package ("RFP") schedules set forth in the following table:

Table SWS-1

Schedule	**Description**
A-5	Summary of total capitalization and the weighted average cost of capital
G-1	Capitalization, the cost of capital and the overall rate of return in conformance with an original cost Rate Base
G-3	Embedded cost of borrowed capital with term of maturity in excess of one year from date of issue
G-4	Cost of short-term borrowed capital
G-5	Embedded cost of preferred stock capital
G-6	Ratio of earnings to fixed charges
G-7	Issuance restrictions on borrowed and preferred stock capital

Schedule	**Description**
G-8	Common stock equity capital
G-9	Historical activity in common stock, paid-in capital, and retained earnings
J-2	Sources of construction funds

Q. Please summarize the recommendations in your testimony.

A. I recommend the New Mexico Public Regulation Commission ("Commission") approve SPS's proposed Test Year WACC as shown in Table SWS-2 and that the Commission remove its restriction capping SPS's actual capital structure at 55% equity in order to allow SPS to efficiently manage capital and to allow SPS to support its credit ratings.

Table SWS-2

		Test Year WACC	
	Ratio	**Rate**	**WACC**
Long-Term Debt	45.23%	4.44%	2.01%
Equity	54.77%	10.35%	5.67%
Total Cost			**7.68%**

Q. Was Attachment SWS-1 prepared by you or under your direct supervision and control?

A. Yes.

Q. Are the remaining attachments to your testimony true and correct copies of the documents you represent them to be?

A. Yes.

Q. Were the portions of the RFP schedules that you sponsor or co-sponsor prepared by you or under your direct supervision and control?

A. Yes.

Q. Do you incorporate the RFP schedules sponsored or co-sponsored by you into your testimony?

A. Yes.

III. FINANCIAL INTEGRITY, RATING AGENCY METHODOLOGIES, AND SOUTHWESTERN PUBLIC SERVICE COMPANY

Q. What topics do you discuss in this section of your testimony?

A. In this section of my testimony, I will:

- Describe the importance that this case will play in supporting SPS's future financial integrity;
- Explain how capital investors evaluate the financial integrity of utilities like SPS and how SPS's current financial integrity appears when viewed through that analysis, including a summary of SPS's key financial metrics; and
- Identify both how SPS is working to maintain its financial integrity and how its financial integrity could be strengthened through a supportive regulatory decision in this case.

A. Financial Integrity

Q. What is financial integrity?

A. As used in my testimony, "financial integrity" refers to a company's financial strength and its ability to attract capital to support operations and infrastructure investment over the course of an economic cycle. The ability to attract capital at a reasonable cost in all market conditions is integral to a utility's obligation to provide safe and reliable utility service. Financial integrity ensures that the utility will have the flexibility to withstand unanticipated macroeconomic events outside of its control.

Q. Have investor perceptions of SPS's regulatory environment impacted their view of SPS's financial integrity?

A. Yes. As I discuss later in my testimony, regulatory outcomes are an important factor that rating agencies rely on to assess a utility's credit quality. In recent years, rating agencies have expressed concern about the rate proceeding outcomes in New Mexico and, to a lesser extent, Texas. The rating agencies have also emphasized the importance of moving toward balanced, constructive outcomes in utility rate proceedings. SPS views this case as an opportunity to shift investor opinion by demonstrating that a supportive regulatory outcome can be achieved in New Mexico.

Q. Have there been any recent outcomes in New Mexico that are positive and could serve as a starting point for improving investor perceptions of SPS's financial integrity?

A. Yes. The recent resolution of the appeals concerning SPS's most recent New Mexico rate case and two other Commission actions represented a positive step that could serve as a starting point for improving perceptions of New Mexico's regulatory impact on SPS's financial integrity.

Q. What is the basis for your opinion?

A. In a report dated October 19, 2018, following the Commission's original final decision in SPS's 2017-18 rate case, Moody's stated:

> Moody's sees more constructive recovery mechanisms available in Texas than in New Mexico, illustrated by the different regulators' responses to the utility's initiatives to offset the impact of the implementation of the TCJA. In Texas, the regulators approved the multi-party settlement that included authorization to earn a 9.5% rate on equity (ROE) on SPS's actual capital structure, which the utility anticipates will include an above average 57 % equity layer. In contrast, the New Mexico Regulatory Commission approved, in September 2018, an increase in SPS's base rates ($8 million) based on a 51% equity ratio, a significant difference compared to SPS's requested 58% equity ratio. This request was updated post tax reform, and could be indicating a less constructive relationship between the utility and the NMPRC.[3]

Subsequently, in February 2019, SPS and the Commission filed a Joint Motion for Remand and Stipulated Dismissal[4] that adjusted the 51% equity ratio to 53.97% (more closely reflecting SPS's actual equity). SPS appreciates this outcome and believes it is a constructive first step; however, in order to minimize the cost of SPS debt issuance, capital market investors need to see consistency and a stable commitment to maintaining a supportive regulatory environment in New Mexico.

[3] Attachment SWS-2 at 1.

[4] *In the Matter of Southwestern Public Service Company's Application for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 272*, Case No. 17-00255-UT, Southwestern Public Service Company and the New Mexico Public Regulation Commission's Joint Motion for Remand and Stipulated Dismissal of SPS's Appeal of the NMPRC's Order (Feb. 15, 2019).

Q. Does this case offer the opportunity to further improve investor perceptions of SPS's financial integrity?

A. Yes. The Commission's approval of a regulated equity ratio of 54.77% in this case as well as the removal of the 55% equity cap would both be positive steps in supporting current credit ratings. Generally, improvements to SPS's credit metrics can be achieved through three avenues: a higher regulated equity ratio, a higher ROE or shortening asset lives to accelerate depreciation. From a revenue requirements perspective, changing the regulated equity ratio is the least impactful to revenue requirements and therefore, the most efficient mechanism to mitigate the credit impacts.

Q. Is this why SPS is requesting that the Commission remove its restriction capping SPS's actual capital structure at 55% equity?

A. Yes. Although SPS is not currently asking for an increase in earned return on the equity ratio over 55%, SPS would like the ability to maintain the equity ratio above 55% in order to manage its capital structure efficiently and in accordance with best cash management practices as well as to support its credit ratings should additional equity be needed.

B. Factors Impacting Financial Integrity

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 other factors can also affect a utility's financial integrity. 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 operations and maintenance, but also the costs of servicing debt and providing a fair return for equity investors. This is why constructive regulatory decisions on capital structure, ROE, and the recovery of prudent utility costs are vitally important to SPS.

Q. Why should the Commission be concerned about SPS's financial integrity?

A. As I mentioned above, financial integrity directly affects SPS's ability to access capital and the cost of that capital, which, in turn, impacts the cost of debt and the cost of equity that must be paid by customers as well as SPS's ability to fund new projects. The ability to attract capital at a reasonable cost in all market conditions is also critical to satisfying SPS's obligation to provide safe and reliable utility service and it helps to ensure that a utility has the flexibility to withstand unanticipated macroeconomic events outside of its control, such as the deep economic downturn that occurred in 2008-2009. In contrast, a company that lacks financial integrity will be limited in its ability to finance assets or undertake new projects, particularly during times of volatility in the capital markets. Weak financial integrity at a utility also increases the issued cost of debt and the implied cost of equity, which increases the overall WACC and the ultimate financing costs which are paid by customers.

Q. Is the outcome of this case uniquely important to how investors will view SPS's ongoing financial integrity?

A. Yes. This case is particularly important for several reasons. First, this case comes soon after a credit downgrade of SPS that was tied closely to concerns with the regulatory environment. Second, SPS currently (and for the foreseeable future) has large needs for raising outside capital (both equity and debt) to support investment necessary to (1) serve the economic expansion in SPS's service territory; and (2) enable customer-benefitting clean-energy initiatives. Finally, this case marks one of the first rate cases that will be decided by the current Commission. Consequently, rating agencies will be looking at the Commission's decision in this case as an indication of whether New Mexico is moving toward a more balanced and constructive regulatory environment that compliments and supports the State's priorities of economic growth and clean and affordable electricity.

Q. Please address the downgrade of SPS.

A. In the fourth quarter 2018, Moody's, which rates SPS on a stand-alone basis (rather than as part of the Xcel Energy "family"), downgraded SPS's credit rating. This deterioration in SPS's credit rating was partially due to concern with the regulatory environment and the lack of regulatory support that SPS was experiencing in New Mexico. This case represents an opportunity to change investor opinion by building on the recent settlement of several SPS appeals of Commission decisions. Improving investor opinion is important to managing future funding costs to ensure that SPS's generation resources and transmission and distribution system can meet long-term growth requirements safely and reliably.

Q. How long does it take to restore credit ratings to their former levels?

A. After any company experiences an extended period of diminished creditworthiness, it takes a long time to restore the credit rating and to regain the confidence of the debt capital markets. The associated higher costs of credit typically persist for many years. Moody's cited that there are limited prospects for a near-term upgrade, but it could be considered if there is positive momentum in the form of higher than anticipated regulatory relief and/or cost savings that allowed SPS to record CFO pre-W/C to debt above 18% for an extended period of time.

Q. Please address SPS's need for capital to support economic growth and the clean energy transition.

A. In light of New Mexico's and SPS's shared priorities for clean and affordable electricity, SPS is in the midst of significant investments in cost-effective, clean electric generation resources that both save customers money and benefit the environment. SPS is also experiencing economic growth in its service territory requiring investment in transmission and distribution infrastructure to provide necessary support for a major growth engine of New Mexico's economy and tax base. Capital investment to achieve these goals will require nearly $7 billion; this type of investment requires long-term commitment. For example, during the five year period from 2014 to 2018, SPS spent approximately $3.25 billion in capital. SPS plans to spend another $3.5 billion during the five-year period from 2019-2023 as shown on Table SWS-3.

Table SWS-3

Year	SPS Capital Investment or Planned Capital Investment[5]
2014 (actual)	$565 million
2015 (actual)	$600 million
2016 (actual)	$513 million
2017 (actual)	$551 million
2018 (actual)	$1,021 million
2019 (forecast)	$1,130 million
2020 (forecast)	$770 million
2021 (forecast)	$460 million
2022 (forecast)	$530 million
2023 (forecast)	$635 million

Q. How will the capital structure adopted in this rate case impact SPS's ability to fund these capital needs?

A. SPS funds its capital needs through a combination of (1) retained earnings or by receiving capital infusions from its parent company; and (2) borrowing. Retained earnings result from equity derived from cash received from customer revenues within SPS (rather than sending those excess funds as dividends to SPS' parent company, Xcel Energy). Accordingly, it is vitally important, particularly in a time of significant capital demands, that the Commission adopt a capital structure

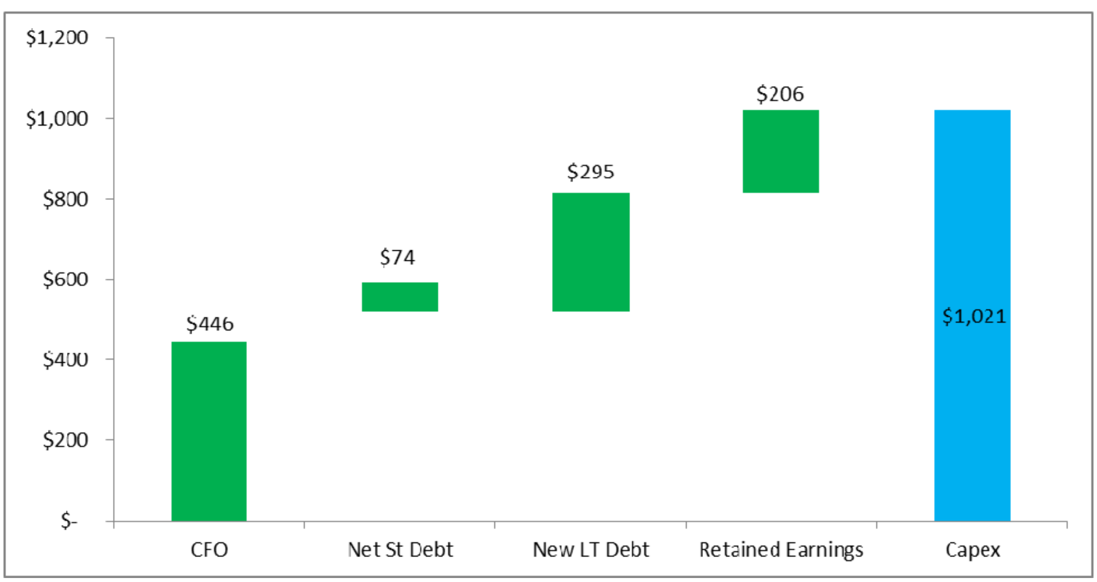
[5] SPS does not forecast capital expenditures on a jurisdictional basis. Thus, these numbers are presented at a total-company level.

that reflects SPS's actual financing practices. Capital structure is the proportion of each source of funding used to support the utility's rate base.

Q. What percentage of SPS's capital needs were met through operating cash flows in 2018?

A. Approximately 44% of SPS's cash needs were met through cash from operations in 2018 as seen in Chart SWS-1 below. Stated differently, the rates SPS charges its customers currently fund only 44% of the capital needed to own, operate, and modernize its electric system. The remainder of required funding must be accessed from outside parties, including investors (shareholders) and creditors (bondholders).

Chart SWS-1: 2018 Sources of Funding for Capital Spend



SPS is forecasting a similar %age of cash flow to total capital spending in 2019. For this reason, SPS's ratemaking capital structure must reflect its actual financing practices in order to provide investors with accurate expectations regarding their investment, maintain SPS's financial integrity, and enable SPS to compete for the investor dollars that are necessary to fund the actual and forecasted capital expenditures shown in Table SWS-3 above.

Q. How do debt and equity investors evaluate a regulated utility's financial integrity?

A. The financial integrity of a regulated utility can largely be viewed as a function of its current capital structure, ROE, and projected cash flow, along with investors' expectations for how the regulated utility will perform on those factors in the future. Investors are well aware that performance on those factors is highly dependent on actions by the utility's state regulatory commission.

Q. Do investors rely on company-specific credit ratings as an indicator of a company's financial strength?

A. Yes. Investors use company-specific credit ratings published by the major independent credit rating agencies—S&P, Moody's, and Fitch—as an indicator of a company's financial strength. While debt investors are more directly reliant on credit ratings, the cost of equity is also impacted. An equity investor's return is residual, meaning that equity investors receive their return after the bond investors. A lower credit rating results in greater risk to both the bond and equity investor. Both the debt and equity investors require higher returns to be compensated for the additional risk.

Q. What are the primary drivers of credit ratings?

A. The primary drivers of credit ratings are business and financial risk.[6] Credit ratings are assigned after the agencies conduct an independent, comprehensive quantitative and qualitative analysis of a company and the business environment in which it operates.

Q. What role does a utility's credit rating play in its ability to access capital on reasonable terms?

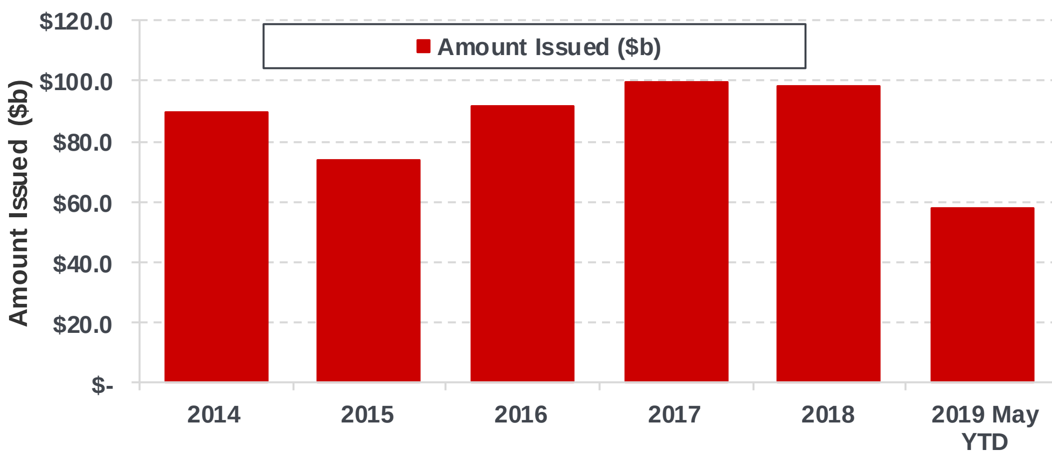
A. Credit ratings help debt investors differentiate between utilities – all of whom are competing (with companies within and outside the utility sector) for the same

[6] Business risk relates to the potential sources of variability in a company's cash flow from its operating conditions as a result of various business factors including: regulatory environment and trends, operational performance, regulatory outcomes, fuel mix and geographic dispersion, and management decisions. Business risk is determined by a company's industry characteristics and peer group comparisons.

Financial risk addresses the ability of a company to make scheduled payments of interest and principal on its financial obligations. To assess a company's financial risk, credit rating agencies evaluate certain financial metrics to determine whether the company has sufficient levels of cash flow to cover its future interest expense and principal payments. It is therefore important for SPS to maintain certain financial metrics in order to maintain its credit ratings.

investment dollars. During the past five and a half years, debt investors have provided approximately $510 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 SWS-2.

Chart SWS-2: 2014-May 2019 Debt Amount Issued to the U.S. Utility Sector



Higher credit ratings are associated with reduced risk, which attract investors at a lower cost of debt and position a utility favorably relative to lower-rated comparable companies. Equity investors also look at credit ratings as a source of information they rely on to differentiate between utilities. Ultimately, customers of the higher-rated utility benefit from lower capital costs.

Q. What do credit rating agencies weigh in evaluating regulated utilities' financial integrity?

A. While the rating agencies vary in their methodology (and the extent to which they explain their methodology to the public), Moody's has provided a fairly complete picture of its methodology. That methodology is useful to illustrate how rating agencies and investors evaluate financial integrity. Moody's identifies four key rating factors that are weighted as follows:

Table SWS-4

Key Rating Factors

Factor	Weighting
Regulatory Framework	25%
Ability to Recover Costs and Earn Returns	25%
Diversification	10%
Financial Strength	40%
Total	100%

Source: *Regulated Electric and Gas Utilities*, Moody's, June 2017.

The "Regulatory Framework" factor 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."[7]

The second factor, the "Ability to Recover Costs and Earn Returns," is also fundamentally dependent on Commission actions. Moody's "evaluates the regulatory elements that directly affect the ability of the utility to generate cash flow and service its debt over time."[8] Moody's views the ability to recover costs on a timely basis and to attract debt and equity capital as critical credit considerations, and, therefore, Moody's seeks to estimate the lag between the time that a utility incurs a major construction expenditure and the time that the utility starts to earn a return of and return on that expenditure. According to Moody's, "[t]he inability to recover costs…has been one of the greatest drivers of financial stress in this sector."[9] That is particularly true when utilities' capital expenditures exceed their cash from operations, resulting in negative cash flow, so any lack of timely recovery or an insufficiency of rates can strain access to capital markets.[10]

[7] Attachment SWS-3 at 6.

[8] Attachment SWS-3 at 12.

[9] Attachment SWS-3 at 12.

[10] A company's revenues and cash flow must keep pace with expense levels. This includes not only operating expenses but also the cost of capital and depreciation for capital investments. To maintain healthy credit metrics, the revenues must closely match the amount and time of incurring the costs.

The third factor is "Diversification," which considers many of the same business risk factors that S&P evaluates. Moody's evaluates the balance among businesses, geographic regions, regulatory regimes, and generating plants or fuel sources.[11]

The fourth factor, "Financial Strength," comprises 40% of the Moody's rating. Similar to S&P, Moody's considers both historical and future data to calculate financial strength metrics and to analyze trends. SPS's financial strength is necessary to attract capital at a reasonable cost to fund its utility investment and fulfill its service obligations to customers at a reasonable cost.[12]

Q. Have other 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."[13] S&P observed further that "[w]e base our assessment of the regulatory framework's credit supportiveness on our view of how regulatory

[11] Attachment SWS-3 at 16.

[12] Attachment SWS-3 at 20.

[13] Attachment SWS-4 at 6.

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."[14] The same document contains an extensive discussion regarding the importance of the regulatory environment in which the utility operates.

Q. Why do rating agencies place such importance on the regulatory environment in evaluating a utility's financial integrity?

A. In order to provide safe, reliable and clean service, utilities require significant capital investment. When a utility is unable to recover costs on a timely basis, the utility's cash flow is adversely impacted. To cover the shortfall, the utility must issue an increased amount of debt. If debt levels increase too much with respect to cash flows from operations, the credit ratings will deteriorate and the utility's access to capital markets can become strained. The alternative would be to reduce levels of investment, which is not supportive of economic growth and development for the company.

[14] Attachment SWS-4 at 6.

Q. Do regulatory proceedings such as this one have the potential to affect a regulated utility's financial integrity?

A. Yes. Rating agencies monitor regulatory outcomes and achieving a balanced, constructive outcome in a rate proceeding is an important factor in their assessment of a utility's credit quality. Significant elements include the utility's authorized ROE, capital structure, and WACC, along with considerations such as the timeliness of recovery of the utility's costs and investments, outcomes on prudence and similar determinations, and other items that impact the utility's revenue.

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 and Fitch through the use of pluses or minuses to show a company's relative standing within the categories.[15] The highest rating is AAA; the lowest investment-grade rating is BBB-. Debt rated BB+ or below is

[15] Moody's uses numbers to show a company's standing within a category.

considered speculative grade. Attachment SWS-5 contains a description of the ratings used by S&P and the corresponding ratings used by Moody's and Fitch.

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: (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"); (iii) the ratio of debt to earnings before interest, taxes, depreciation, and amortization ("Debt/EBITDA"); and to a lesser extent (iv) the ratio of total debt to total capital ("Total Debt/Total Capital"). These financial metrics are a composite measure of the utility's ability to meet its financial obligations when they are due. The greater the *business* risk of a particular company, the stronger these financial metrics must be to provide sufficient evidence to the credit rating agencies and investors that the company can withstand the financial effect of both macroeconomic and company-specific risks.

Q. What is the significance of the metrics the credit rating agencies evaluate?

A. The metrics help 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. Because strong cash flow coverage is critical to cover existing and future obligations, the equity ratio and ROE are crucial to a utility's financial integrity as both affect cash flow.

Q. Do the rating agencies consider on-balance sheet obligations and off-balance sheet obligations in their credit metrics calculations to help evaluate a utility's financial risk?

A. Yes. The ratio of Total Debt/Total Capital provides a long-term measure of a company's financial risk, and historically a debt to capital ratio of 45% to 50% was the S&P guideline for a "significant" financial risk profile. The total debt in these metrics includes amounts for on-balance sheet obligations such as finance and operating leases and short-term debt, as well as off-balance sheet obligations.[16] Expressed in terms of equity ratio as used in Commission proceedings, approval of SPS's requested 45.23% debt to 54.77% equity ratio equates to a 50.39% debt to 49.61% equity ratio once off-balance sheet obligations are accounted for as shown in Table SWS-9 below. This would put SPS outside the acceptable guideline for "significant." Moreover, as the level of debt in a company's capital structure increases, so does the level of interest expense that must be serviced. An increased level of interest expense requires

[16] Off-balance sheet obligations are payment obligations that do not appear on the balance sheet as debt, but rating agencies may treat them as debt in terms of calculating metrics because the utility has little or no discretion in terms of payment. Please refer to pages 14 to 16 of Attachment SWS-4 for further discussion on purchased power adjustments, and please refer to Attachment SWS-6 for discussion on S&P's Corporate Methodology: Ratios and Adjustments.

higher levels of cash flow to produce adequate levels of interest coverage. All else equal, a lower equity ratio will generate less cash flow, assuming the equity return is held constant. In general, the higher the proportion of debt in a capital structure, the more pressure on cash flow metrics and credit ratings.

Q. Does S&P rate SPS based on metrics specific to SPS?

A. No. S&P looks at Xcel Energy as a whole, and provides a "family" rating under which each of Xcel Energy and its utilities automatically receive the same ratings. Moody's and Fitch both perform an SPS-specific evaluation.

Q. Do the rating agencies consider identical factors in establishing credit ratings?

A. No. The factors are not identical or given identical weight, but each of the agencies conducts some form of business risk and financial metrics analysis. S&P's methodology includes financial ratios and risk matrices, some of which are shown in Table SWS-5.

Table SWS-5

S&P's Financial Risk Indicative Ratios: Medial Volatility			
	FFO/Debt (%)	**Debt/EBITDA (x)**	**EBITDA/Interest (x)**
Modest	35 - 50	1.75 - 2.5	9 – 14
Intermediate	23 - 35	2.5 - 3.5	5 – 9
Significant	**13 - 23**	**3.5 - 4.5**	**2.75 – 5**
Aggressive	9 - 13	4.5 - 5.5	1.75 – 2.75

Q. Please explain Table SWS-5.

A. Table SWS-5 illustrates the required ratios under the medial volatility matrix (as assigned to SPS by S&P) at the various levels of financial risk. For example, a "Significant" financial risk profile requires a company to consistently have a FFO/Debt ratio of 13-23 (or greater), a Debt-to-EBITDA ratio of 3.5-4.5 (or less), and an EBITDA-to-Interest ratio of 2.75 or greater. This matrix stresses the importance of financial risk profile.

Q. What factors does Moody's consider?

A. Moody's considers both business and financial risk, some of which are shown in Table SWS-6.

Table SWS-6

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%

Q: Please explain Table SWS-6.

A. Table SWS-6 illustrates the required ratios under the standard model (as assigned to SPS by Moody's) at the various levels of financial risk. For example, in order to maintain a Baa rating under the standard grid profile requires a company to consistently have a CFO pre- WC/Debt ratio of 13%-22% (or greater), a CFO pre-WC + Interest/Interest ratio of 3.0x – 4.5x (or greater), a CFO pre-WC – Dividends/Debt ratio of 9%-17% (or greater) and a Debt/Capitalization ratio of 45-55% (or lower). This matrix also stresses the importance of financial risk profile. Moody's has set a threshold specifically for SPS for the CFO pre-WC/Debt metric and has specifically stated that a CFO pre-WC/Debt ratio of less than 16% could result in a downgrade to SPS's ratings[17].

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 a utility's earnings and directly affect its ability to fund capital investment with internally generated funds. Both debt and equity investors expect a utility to be

[17] Attachment SWS-2 at 2.

able to internally generate a substantial portion of its investment funding.

- Second, the capital structure and authorized costs directly affect all of the utility'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 the company is appropriately capitalized given its business risk profile and to determine whether the company has the ability to issue additional debt to fund its utility capital expenditures. The rating agencies include off-balance sheet obligation adjustments in their debt valuation, placing further pressure on the financial metrics. 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 the utility to be able to recover its costs in a timely manner and to have an opportunity to earn its authorized ROE. Investors' and credit rating agencies' perceptions regarding the regulatory environment in which we operate are an important consideration in assessing a utility's business risk. Investors and rating agencies track the decisions of regulatory agencies relating to capital structure, cost of debt, ROE, and forward-looking cost recovery mechanisms, and they categorize the state regulatory environments in their assessment of the relative risks of different utility investment opportunities.

Moreover, the earned ROE, the actual capital structure, and the timely recovery of expenses and investments all factor heavily into the financial metrics I have already discussed.

C. SPS's Financial Integrity and Credit Metrics

Q. What topics do you discuss in this section of your testimony?

A. I describe assessments of SPS's financial integrity, including as specified through its credit ratings, and explain how they have changed over time. The discussion includes SPS's business and financial risks, including regulatory risk.

Q. What are SPS's current credit ratings?

A. SPS currently has a corporate credit rating of A- from S&P and BBB from both Moodys' and Fitch, as reflected in Table SWS-7 below.

Table SWS-7

	S&P*	Moody's	Moody's S&P Equivalent	Fitch
Corporate Rating	A-	Baa2	BBB	BBB
Senior Secured	A	A3	A-	A-
Senior Unsecured	A-	Baa2	BBB	BBB+
Commercial Paper	A-2	P-2	N/A	F2

*S&P "family" rating of SPS

SPS's ratings were downgraded by Moody's in October 2018 as shown in Table SWS-8.[18]

[18] Attachment SWS-2 at 1.

Table SWS-8

Moody's Ratings	Current Rating	Prior Rating
Issuer Rating	Baa2	Baa1
Senior Secured-FMB	A3	A2
Senior Unsecured-Bank Credit Facility	Baa2	Baa1
Commercial Paper	P-2	P-2

S&P has not taken action on SPS's credit ratings, in part because SPS benefits from "family style" ratings by S&P; meaning, the issuer credit rating for SPS is equal to Xcel Energy's group credit profile, and is therefore benefitted by SPS having sister utilities that operate in regulatory environments that investors view as relatively more supportive of the financial integrity of regulated utilities.

Q. How have the rating agencies historically viewed the regulatory environment in which SPS operates?

A. In a report dated October 19, 2018, Moody's states that the downgraded Baa2 rating "considers our mixed view on the credit supportiveness of the regulatory environments under which SPS operates."[19]

Similarly, in a report dated July 11, 2018, Fitch stated "Fitch Ratings considers the regulatory environment overseen by the Public Utility Commission of Texas (PUCT) and the New Mexico Public Regulation Commission (NMPRC)

[19] Attachment SWS-2 at 1.

to be “challenging… Electric utilities in Texas and New Mexico have historically received authorized ROEs that are slightly lower than the nationwide average. In addition, regulatory lag from the use of a historical test year in Texas and other factors in the ratemaking process in New Mexico have made it difficult for SPS to earn its low authorized ROEs.”[20]

In a September 5, 2018, report titled RRA Financial Focus, S&P assigned New Mexico a Below Average ranking, indicating a less constructive, high-risk regulatory climate from an investor standpoint.[21] In another publication, S&P Global Market Intelligence: New Mexico Public Regulation Commission reached the same conclusion.[22]

RRA also published a report entitled “State Regulatory Evaluations: that assesses the regulatory climates for energy utilities. RRA assigns 3 levels of “below average” rating; below average 1, below average 2 and below average 3. New Mexico is rated as below average 2, which puts it in the bottom rated 4 jurisdictions out of 53 total jurisdictions within the 50 states.[23]

[20] Attachment SWS-7 at 1.

[21] Attachment SWS-8 at 6.

[22] Attachment SWS-9 at 2.

[23] Attachment SWS-10 at 1 and 6.

Q. Should the Commission be concerned with the rating agencies' analysis and ratings of SPS?

A. Yes. For regulated utilities, investors tend to prefer stable regulatory environments because this simplifies pricing risk and enables investors to generate predictable returns. Equity investors base their decisions on growth and future returns so their models focus on forward-looking projections as described by Ms. Bulkley in her direct estimony. In addressing this prospective emphasis, equity analyst comments tend to be predictive.

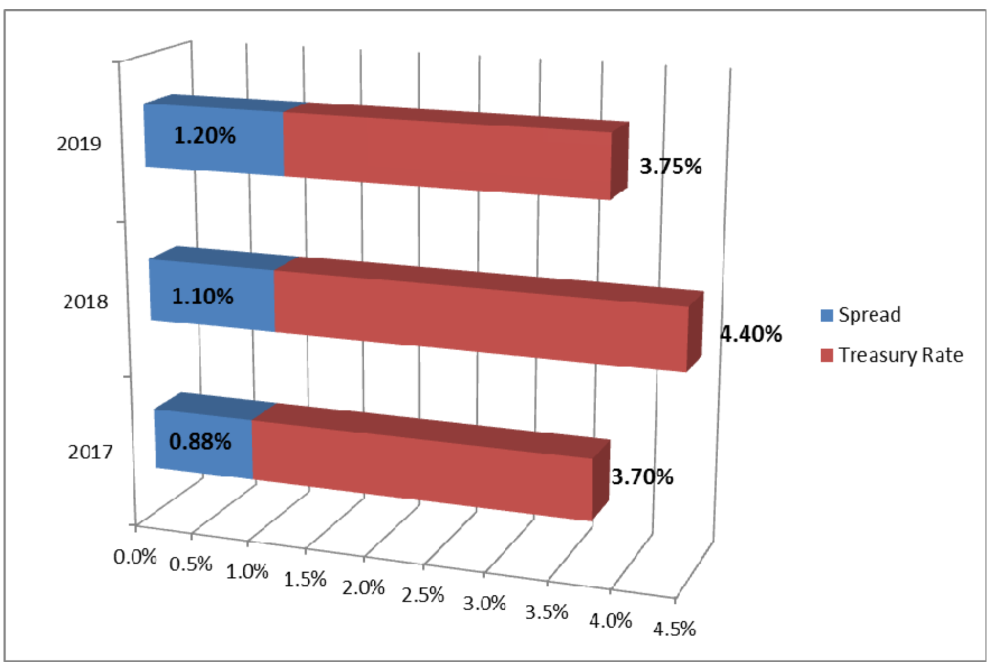
Q What impact is SPS's credit rating expected to have on its long-term cost of debt?

A. New long-term debt is priced based on the underlying Treasury rate plus a credit spread, which is based on SPS's credit rating. In general, the lower the credit rating, the higher the credit spread. Issuing debt at a higher rate will increase the long-term cost of debt for SPS. This will ultimately increase the cost of debt paid for by SPS's customers. Under current market conditions, the recent downgrade to the credit rating could cause the cost of new long-term debt to increase approximately 15-20 basis points based on recent indicative pricing estimates from our issuing credit banks.[24]

[24] Attachment SWS-11 at 1. This is the difference between the SPS indicative spread and that of either NSPM or PSCo, both of which have higher credit ratings.

For example, while SPS priced and settled a new 30-year “green” first mortgage bond in June 2019 at a coupon of 3.75% this represents a continuing trend of issuing at low coupons as a result of lower Treasury rates. As demonstrated in Chart SWS-3, Treasury rates over the last 3 years have steadily declined due to market conditions; however, the credit spread component of the overall coupon rate, which reflects the credit spread charged to SPS by investors, has increased almost 40% during this same period reflecting investors perception that SPS’s risk has increased.

Chart SWS-3: Components of SPS Coupons 2017-2019

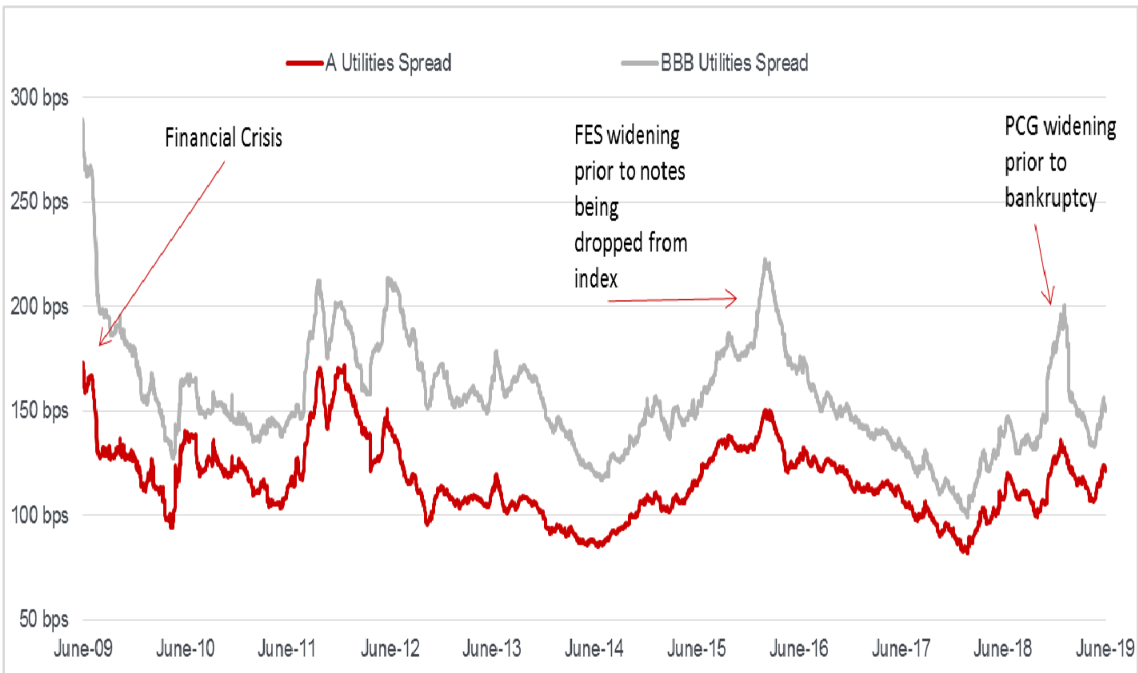


Moreover, economic downturns can have a material effect on a utility's access to capital, as evidenced by the deep recession that began in 2008. During those periods of economic distress, the effects of credit ratings are magnified. In 2008, for example, utilities with A ratings generally had adequate access to credit at a reasonable cost. On the other hand, utilities with BBB ratings had to pay much higher costs for debt capital, and in some instances they could not borrow at all. SPS witnessed this first hand as it struggled to access the long-term debt market in 2008 and had to issue a 10-year bond with a coupon of 8.75%, which impacted the overall cost of capital for SPS.

Q. Do credit spreads differ based on credit ratings?

A. Yes. Chart SWS-4 shows that the credit spreads of BBB rated utility companies are historically wider than those of A rated utility companies, especially in times of market volatility. This chart demonstrates that although in current market conditions the credit spread between A and BBB ratings is approximately 30 basis points, in periods of market volatility, such as June 2009, the credit spread increased dramatically, at an average spread of 100 basis points. Therefore, focusing on the total coupon rate SPS has received in recent times ignores the impact of the credit rating on the credit spread component of bond pricing.

Chart SWS-4: A vs. BBB Rated Utility Spreads



Source: Bloomberg

Q. Does a lower credit rating have impacts that extend beyond the long-term cost of debt?

A. Yes. A downgrade could also affect SPS's cost of daily business or access to its short-term liquidity. The daily business of SPS is comprised of ongoing credit facility fees, letters of credit to support utility operations, and commercial paper rates. If SPS were downgraded such that it lost its A2/P2/F2 commercial paper rating, SPS would need to borrow directly from its $500 million credit facility and pay up to 100 basis points higher than our current commercial paper rate, which translates to approximately $1 million in additional annual debt expense for every $100 million borrowed, given the current rate environment. During the Financial Crisis in 2007/2008, even though SPS still had its A2/P2 commercial paper rating, SPS was forced to borrow against their credit facility rather than issuing commercial paper due to extreme market volatility. SPS borrowed $125 million against its then $250 million credit facility at a cost of approximately 6%. The only companies that retained reasonably-priced access to short-term commercial paper markets during October 2007 were companies with short-term ratings of A1/P1.

D. Maintaining and Strengthening SPS'S Financial Integrity

Q. Have you assessed what financial metrics SPS must maintain in order to maintain its current credit ratings?

A. Yes. With a 54.77% regulated equity ratio: (1) the economic equity ratio including debt adjustments from S&P is 49.6%, within the range of 45-50% to support the A- corporate rating; and (2) the FFO/Debt ratios continue to support the A- rating under S&P's methodology. The Debt/EBITDA ratios, however, increase as shown on Table SWS-10 and are outside of the range for A- rating, reflecting continued pressure on the current credit ratings.

Table SWS-9

as of 3/31/19	Regulated			Economic			
Short Term Debt	$ -	0.00%		$ 175.0	3.43%		
Off Balance Sheet Debt	-	0.00%		272.0	5.33%		
Long Term Debt	2,092.9	45.23%	Total Debt	2,126.3	41.64%	50.39%	Total Debt
Common Equity	2,534.5	54.77%	Total Equity	2,533.2	49.61%	49.61%	Total Equity
	$ 4,627.4	100.00%		$ 5,106.5	100.00%	100.00%	

Table SWS-10: S&P Metrics at 54.77% Regulated Equity Ratio

A Corp. Rating Medial Volatility	S&P Guidelines	Actual 2017	Actual 2018	Forecast 2019	Forecast 2020	Forecast 2021
FFO/Debt *	**no less than 13-23**	22.1%	18.3%	***17.0%***	***17.0%***	***17.7%***
Debt/EBITDA**	**no more than 3.5-4.5**	4.1x	4.4x	***4.5x***	***4.9x***	***4.7x***
Debt/Capital***	**no more than 45-50%**	50.4%	49.9%	***48.4%***	***49.6%***	***47.7%***

* (Funds from Operations/Total Debt including adjustments)
** (Debt including adjustments/Earnings before interest taxes depreciation and amortization)
*** (Adjusted Debt/Total Capital), historical standard matrix

Q. What are the projected metrics under Moody's methodology?

A. Financial metrics account for 40% of Moody's methodology grid, with the CFO/Debt ratio being the most important financial measure. In a 55% regulated equity ratio analysis, all CFO/Debt metrics are forecasted to be above 16%, which is the new trigger for a downgrade at a Baa2 rating. This is not sufficient to regain the former Baa1 rating, with a downgrade trigger ("floor") at 20%.

Table SWS-11: Moody's Debt Metrics at 54.77% Regulated Equity Ratio

Guidelines for Baa2 Corp. Rating	Moody's Guidelines	Moody's 2017	Actual 2018	Forecast 2019	Forecast 2020	Forecast 2021
CFO pre-WC/Interest*	**no less than 3x – 4.5x**	5.9x	5.8x	***5.5x***	***5.6x***	***5.2x***
CFO pre w/c /Debt**	**no less than 13 - 22%**	22.6%	18.6%	***17.8%***	***17.6%***	***18.2%***
CFO-Div/Debt***	**no less than 9 – 17%**	17.2%	13.0%	***10.8%***	***11.1%***	***11.0%***

* (Cash from Operations before working capital plus interest/interest)
** (Cash from Operations before working capital/Debt). SPS threshold for downgrade is 16% per Moody's report
*** (Cash from Operations before working capital-Dividends/Debt)

Q. Does SPS face business and financial risk that could imperil its current credit ratings and outlooks?

A. Yes. First, SPS must contend with a number of business and financial risks that could jeopardize its current credit ratings and outlooks. For example, as I noted earlier, SPS will be making substantial capital investments over the next few years, and it will need access to the debt and equity markets to fund a portion of those investments.

Second, SPS has a number of off-balance sheet obligations such as purchased power commitments, operating leases, guarantees, asset retirement obligations, underfunded pension or other benefit plans, and other. During 2018, S&P identified $272 million of debt adjustments for off-balance sheet items for SPS, of which approximately 80% were for purchased power agreements and operating leases. After those off-balance sheet obligations are taken into account, the actual economic equity ratio considered by the rating agencies is far lower than the regulated equity ratio. For example, a regulated equity ratio of 54.77% translates to an economic equity ratio of 49.61% under S&P's methodology. The regulated equity ratio understates true leverage because it excludes off balance sheet items as well as short-term debt. See Table SWS-9.

Third, SPS faces regulatory risk as rating agencies and investors feel that New Mexico is somewhat of a challenging regulatory environment. As I explained earlier, rating agencies place significant weight on consistent and predictable regulatory treatment. This is likely to increase the cost that investors require to purchase the Company's securities – and, ultimately, the cost that is passed on to customers.

IV. CAPITAL STRUCTURE

Q. What are SPS's actual capital structure and cost of capital?

A. The actual capital structure and cost of debt as of March 31, 2019 are shown in Table SWS-12 below, including an earned ROE of 9.56%.[25] The detailed schedules are included in Schedule A-5.

Table SWS-12

		March 31, 2019 Actual	
	Ratio	**Rate**	**Wtd Cost**
Long-Term Debt	45.23%	4.51%	2.04%
Equity	54.77%	9.56%	5.67%
Total Cost			**7.28%**

Q. What is SPS's proposed Test Year capital structure and cost of capital?

A. SPS's proposed Test Year WACC is 7.68% as shown below in Table SWS-13. The Test Year WACC is based on an ROE of 10.35%, a long-term debt cost of 4.44%, and a capital structure composed of 54.77% common equity and 45.23% long-term debt.

[25] Reflects authorized Return on Equity in SPS's most recently litigated base rate case, Case No. 17-00255-UT.

Table SWS-13

		Proposed Test Year WACC	
	Ratio	**Rate**	**Wtd Cost**
Long-Term Debt	45.23%	4.44%	2.01%
Equity	54.77%	10.35%	5.67%
Total Cost			**7.68%**

Q. What is SPS's recommended capital structure?

A. SPS recommends a capital structure consisting of 54.77% equity and 45.23% long-term debt. The use of SPS's actual capital structure is reasonable in this case, in large part because it will help maintain SPS's current crediting ratings. Since SPS operates in two jurisdictions, it is regulated by two independent commissions: New Mexico and Texas. The independent regulation of this single entity has resulted in two separate capital structures with separate required equity ratios. This is disadvantageous for SPS from a capital structuring standpoint and is a challenge to manage operationally because this is one consolidated company. In order to maintain strong credit metrics which lead to higher credit ratings and lower cost for customers, it is reasonable to put SPS on a path towards a consistent capital structure between its two jurisdictions. This further supports

SPS's request that the Commission remove its restriction capping SPS's actual capital structure at 55% equity.

Q. Does this capital structure reflect SPS's actual financing practices?

A. Yes.

Q. Is it important that the Commission adopt a capital structure that reflects SPS's actual financing practices?

A. Yes. As noted earlier in the Financial Integrity section, it is important that the Commission adopt a capital structure that reflects SPS's actual financing practices. With the increase in capital expenditures over the next two years, SPS's capital structure needs to support this growth.

Q. Will approval of SPS's equity of 54.77% as the regulated equity ratio mitigate additional downward pressure on its financial strength?

A. Yes. However, even at 54.77% equity, the downward pressure on SPS's credit metrics will continue. As I explained above, an equity ratio below 54.77% will not meet the credit rating agencies' published metrics for an A3/A- public utility.

Q. Why is it important for SPS to maintain its A-/BBB corporate rating?

A. First, SPS has been able to maintain the A- rating from S&P because S&P uses the Xcel Energy group in its entirety to assess the overall credit risk. All operating companies and Xcel Energy have A- corporate rating from S&P. SPS's corporate credit rating at BBB by both Moodys' and Fitch is the lowest in the Xcel family, lower than Moody's and Fitch credit rating for the Xcel Energy holding company at Baa1 and BBB+. A one notch downgrade by Moody's or Fitch at SPS would result in a BBB- equivalent rating, just one notch away from junk bond status.

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.[26]

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

V. COST OF LONG-TERM DEBT

Q. What was SPS's embedded cost of long-term debt as of March 31, 2019?

A. SPS's embedded cost of long-term debt as of March 31, 2019 was 4.51%. The detailed calculation is shown in rate filing package Schedule G-3 and is consistent with the method this Commission has approved in the past. The cost of debt is based on a yield-to-maturity calculation where the debt expenses include interest as well as fees associated with issuing the bond, such as legal, underwriting, rating agency and other costs. These annualized costs are divided by the net proceeds of the bonds outstanding to derive an overall cost of debt for SPS.

Q. Why did SPS's actual embedded cost of long-term debt change after the end of the March 31, 2019 Base Period?

A. On June 11, 2019, SPS issued a $300 million, 30-year "green" first mortgage bond that SPS priced at a 3.75% coupon, thus lowering the cost of long-term debt from 4.51% to 4.44%. SPS was able to price and settle at this coupon rate by relying on the Xcel Energy "family" credit rating, not its stand-alone rating, and the current trend of lower Treasury rates.

Q. Has SPS reflected this change in its proposed WACC?

A. Yes. We work hard to manage the cost of debt efficiently for customers and want them to receive the benefit of our success in negotiating a new first mortgage bond at favorable rates. This is, however, becoming increasingly challenging in light of investor perceptions of SPS's financial integrity and the regulatory environment in which SPS operates and illustrates the importance of a supportive regulatory outcome in this case that approves SPS's proposed WACC and eliminates the 55% equity ratio cap. This result will allow SPS to efficiently manage capital, support its credit ratings, and fund the investment necessary to serve the economic expansion in SPS's service territory and enable customer-benefitting clean-energy initiatives.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

VERIFICATION

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

SARAH W. SOONG, first being sworn on her oath, states:

I am the witness identified in the preceding direct testimony. I have read the direct testimony and the accompanying attachment(s) and am familiar with their contents. Based upon my personal knowledge, the facts stated in the testimony are true. In addition, in my judgment and based upon my professional experience, the opinions and conclusions stated in the testimony are true, valid, and accurate.

Sarah W. Soong
SARAH W. SOONG

SUBSCRIBED AND SWORN TO before me this 24th day of June, 2019 by SARAH W. SOONG.

PAMELA C. WILSON
NOTARY PUBLIC - MINNESOTA
My Commission Expires
January 31, 2020

Pamela C. Wilson
Notary Public of the State of Minnesota
My Commission Expires: 1-31-2020

Statement of Qualifications

Sarah W. Soong

I received my Bachelor of Arts degree in Government in 1992 from the College of William and Mary, my Master of Arts degree in Western European and French Studies in 1997 from Lauder Institute at the University of Pennsylvania and my Master of Business Administration degree in Finance in 1997 from The Warton School at the University of Pennsylvania.

My current position with Xcel Energy is Vice President and Treasurer. I have been employed by Xcel Energy Inc. since August 2018. 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 management, pension plan management, hazard risk insurance, and treasury forecasting.

I worked for ONCOR Electric Delivery Company, LLC in Dallas, Texas from 2017 through 2018 as the Vice President and Treasurer. I also worked for Hunt Consolidated Inc. in Dallas, Texas from 2005 through 2017. I started as the Manager of Corporate Finance from 2005 through 2010, followed by the Director of Project Finance from 2010 through 2012 and finally as the Vice President of Project Finance from 2012 through 2017.

From 2004 through 2005 I worked for The Neiman Marcus Group Inc. in Dallas, Texas as the Manager of Corporate Finance. I worked for Exodus Energy, LLC., in Houston, Texas in 2003 as the Director and for Enron Corporation in Houston, Texas from 1997 through 2002 as the Manager of Global Finance and Treasury.

I worked for ABN Amro Bank, Netherlands, Czech Republic from 1993 through 1995 as the Relationships Manager, Global Clients. I worked for N.M. Rothschild and ČESKOSLOVENSKÁ OBCHODNÍ BANKA (ČSOB), Prague, Czech Republic during 1993 as the Financial Advisor and Consultant to N.M. Rothschild on behalf of ČSOB.

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's changes Xcel Energy's outlook to negative; downgrades Southwestern Public Service ratings to Baa2 with stable outlook

19 Oct 2018

Approximately $19 billion of debt securities affected

New York, October 19, 2018 -- Moody's Investors Service ("Moody's") changed the rating outlook of Xcel Energy Inc. (Xcel) to negative from stable and affirmed the A3 senior unsecured and Prime-2 short-term rating for commercial paper ratings.

At the same time, Moody's downgraded the long-term ratings of Southwestern Public Service Company (SPS) including the Issuer rating to Baa2 from Baa1 and affirmed SPS' P-2 short-term rating. The outlook for SPS was changed to stable from negative.

Moody's also affirmed the ratings and outlooks of the Xcel other rated subsidiaries: Northern States Power Company (Minnesota) (NSP-Minnesota, A2 stable), Public Service Company of Colorado (PSCO, A3 stable), and Northern States Power Company (Wisconsin) (NSP-Wisconsin, A2 stable).

RATINGS RATIONALE

"Xcel Energy's financial ratios will be lower for longer due to the cash flow leakage associated with tax reform and an elevated investment program primarily funded with debt" said Natividad Martel, Vice President - Senior Analyst. "The negative outlook reflects consolidated cash flow to debt ratios falling to the 16%-17% range over the next few years, down from around 20% over the last several years."

Xcel's A3 rating factors the group's fully regulated operations and its geographic and operational diversity benefits, as well as our view that the eight regulatory jurisdictions in which its four utility subsidiaries operate are overall credit supportive. The rating considers Xcel's improving carbon transition risk exposure, with an accelerating "steel for fuel" program where the company is replacing fossil-fired generation with renewable generation. The rating also factors in the $300 million equity issuance initiated September 2018 and the structurally subordinated position of the parent level debt vis-à-vis the debt outstanding at its utility subsidiaries, with holding company debt relative to total consolidated debt expected to remain below 25% (currently around 22%).

Southwestern Public Service Company (SPS)

The downgrade of SPS' ratings reflects a weakening in the utility's credit metrics, such that its ratio of CFO pre-W/C to debt is anticipated to drop to nearly 16% by next year, a material deterioration compared to the 22% ratio that SPS generated for the last twelve month period ended 30 June 2018. SPS' Baa2 rating and stable outlook incorporate the expectation that its CFO pre-W/C to debt ratio will remain in the 16%-17% range over the foreseeable future. The Baa2 rating considers our mixed view of the credit supportiveness of the regulatory environments under which SPS operates. Moody's sees more constructive recovery mechanisms available in Texas than in New Mexico, illustrated by the different regulators' responses to the utility's initiatives to offset the impact of the implementation of the TCJA. In Texas, the regulators approved the multi-party settlement that included authorization to earn a 9.5% rate on equity (ROE) on SPS' actual capital structure, which the utility anticipates will include an above average 57% equity layer. In contrast, the New Mexico Regulatory Commission approved, in September 2018, an increase in SPS' base rates ($8 million) based on a 51% equity ratio, a significant difference compared to SPS' requested 58% equity ratio. This request was updated post-tax reform, and could be indicating a less constructive relationship between the utility and the NMPRC. The combination of the utilities' investment program along with the exposure of its cash flows to regulatory lag, particularly due to the absence of any transmission and distribution riders in New Mexico, contribute to the extended deterioration in the utility's financial profile.

NSP-Minnesota, PSCO and NSP-Wisconsin

The affirmation of the ratings of NSP-Minnesota (A2, stable), NSP-Wisconsin (A2 stable) and PSCO (A3 stable) consider our view that all three utilities maintain a reasonably constructive relationship with their respective regulators. The rating affirmations incorporate the expectation that the outcomes of pending regulatory decisions, including the need to address tax reform cash flows, will be a net credit positive. In some states, these measures include the deferral of portions of the excess deferred tax liabilities (EDTL) to be refunded to end-users. In Colorado, PSCO was allowed to amortize prepaid pension assets as an offset of refunds in 2018 and 2019. PSCO has also requested an increase in its the equity ratio to 56% in the Colorado natural gas TCJA true-up proceeding with the decision expected later this year. The stable outlooks assume that these regulatory initiatives along with the reduction in the utilities' base case investments will help to partially mitigate the anticipated weakening in the credit metrics. Importantly, the stable outlooks also assume that each of these utilities will continue to generate CFO pre-W/C to debt in excess of 20%, on a sustained basis.

WHAT CAN CHANGE THE RATING - DOWN

Xcel's ratings could be downgraded if the consolidated ratio of CFO pre-W/C to debt remains below 18% for a sustained basis, or there is no transparent path to improve the ratio over the next few years. The ratings of NSP-Minnesota, NSP-Wisconsin, PSCO and SPS could be downgraded if we perceive a deterioration in the credit supportiveness of their regulatory environments, or if their credit metrics deteriorate more than currently anticipated. Specifically, downward pressure on the ratings of NSP-Minnesota and NSP-Wisconsin could result if their CFO pre-W/C to debt ratios fall to the low 20% range, for an extended period.

In the case of PSCO and SPS, producing CFO pre-W/C to debt below 20% and 16%, respectively, on a sustained basis, is also likely to result in a downgrade of their ratings.

WHAT CAN CHANGE THE RATING - UP

Given Xcel's negative outlook, there are limited prospects for a near term upgrade. However, the outlook could be stabilized if we see a clear path for Xcel to record again CFO pre-W/C to debt in excess of 18%, on a sustained basis.

Positive momentum on the ratings of NSP-Minnesota, NSP-Wisconsin, PSCO and SPS is also unlikely given our expectation that their weakening credit metrics will result in their credit profiles to be commensurate with their current ratings. Longer term, the utilities' ratings could experience positive momentum if higher than anticipated regulatory relief and/or cost savings allow them to record CFO pre-W/C to debt in the high 20% in the case of NSP-Minnesota and NSP-Wisconsin, 25% in the case of PSCO, and 18% in the case of SPS.

Downgrades:

..Issuer: Southwestern Public Service Company

.... Issuer Rating, Downgraded to Baa2 from Baa1

....Senior Secured Shelf, Downgraded to (P)A3 from (P)A2

....Senior Unsecured Shelf, Downgraded to (P)Baa2 from (P)Baa1

....Senior Secured First Mortgage Bonds, Downgraded to A3 from A2

....Senior Unsecured Bank Credit Facility, Downgraded to Baa2 from Baa1

....Senior Unsecured Regular Bond/Debenture, Downgraded to Baa2 from Baa1

Outlook Actions:

..Issuer: Northern States Power Company (Minnesota)

....Outlook, Remains Stable

..Issuer: Northern States Power Company (Wisconsin)

....Outlook, Remains Stable

..Issuer: Public Service Company of Colorado

....Outlook, Remains Stable

..Issuer: Southwestern Public Service Company

....Outlook, Changed To Stable From Negative

..Issuer: Xcel Energy Inc.

....Outlook, Changed To Negative From Stable

Affirmations:

..Issuer: La Crosse (City of) WI

....Senior Unsecured Revenue Bonds, Affirmed A2

..Issuer: Northern States Power Company (Minnesota)

.... Issuer Rating, Affirmed A2

....Senior Unsecured Shelf, Affirmed (P)A2

....Senior Secured Shelf, Affirmed (P)Aa3

....Senior Secured First Mortgage Bonds, Affirmed Aa3

....Underlying Senior Secured First Mortgage Bonds, Affirmed Aa3

....Senior Unsecured Bank Credit Facility, Affirmed A2

....Senior Unsecured Commercial Paper, Affirmed P-1

..Issuer: Northern States Power Company (Wisconsin)

....Senior Unsecured Shelf, Affirmed (P)A2

....Senior Secured Shelf, Affirmed (P)Aa3

....Senior Secured First Mortgage Bonds, Affirmed Aa3

....Senior Unsecured Bank Credit Facility, Affirmed A2

....Senior Unsecured Commercial Paper, Affirmed P-1

..Issuer: Public Service Company of Colorado

.... Commercial Paper, Affirmed P-2

.... Issuer Rating, Affirmed A3

....Senior Secured Shelf, Affirmed (P)A1

....Senior Unsecured Shelf, Affirmed (P)A3

....Senior Secured First Mortgage Bonds, Affirmed A1

....Senior Unsecured Bank Credit Facility, Affirmed A3

..Issuer: Pueblo (County of) CO

....Senior Unsecured Revenue Bonds, Affirmed A3

....Underlying Senior Unsecured Revenue Bonds, Affirmed A3

..Issuer: Southwestern Public Service Company

....Senior Unsecured Commercial Paper, Affirmed P-2

..Issuer: Xcel Energy Inc.

.... Issuer Rating, Affirmed A3

....Senior Unsecured Shelf, Affirmed (P)A3

....Subordinate Shelf, Affirmed (P)Baa1

....Preferred Shelf, Affirmed (P)Baa2

....Junior Subordinate Shelf, Affirmed (P)Baa1

....Senior Unsecured Bank Credit Facility, Affirmed A3

....Senior Unsecured Commercial Paper, Affirmed P-2

....Senior Unsecured Regular Bond/Debenture, Affirmed A3

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in June 2017. Please see the Rating Methodologies page on www.moodys.com for a copy of this methodology.

Xcel Energy Inc. (Xcel) is a holding company for vertically integrated utility subsidiaries, namely Northern States Power Company (Minnesota) (NSP-Minnesota, A2 stable), Public Service Company of Colorado (PSCo, A3 stable), Southwestern Public Service Company (SPS, Baa2 stable), and Northern States Power Company (Wisconsin) (NSP-Wisconsin, A2 stable). These subsidiaries serve 3.6 million electric and 2.0 million natural gas customers in eight states, but mostly in Minnesota, Colorado, New Mexico, Texas, and Wisconsin.

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

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

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

IMPACT ON OUTSTANDING RATINGS

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

EFFECTIVE DATE AND TRANSITION

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

METHODOLOGY

Part I--Business Risk Analysis

Industry risk

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

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

Cyclicality

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

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

Competitive risk and growth

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

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

Effectiveness of barriers to entry--low risk

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

Level and trend of industry profit margins--low risk

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

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

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

Risk in industry growth trends--low risk

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

B. Country risk

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

C. Competitive position

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

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

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

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

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

Assessing regulatory advantage

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

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

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

24. Regulatory stability:

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

25. Tariff-setting procedures and design:

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

26. Financial stability:

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

27. Regulatory independence and insulation:

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

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

Table 1

Preliminary Regulatory Advantage Assessment

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

Table 1

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

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

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

Table 2

Determining The Final Regulatory Advantage Assessment

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

Scale, scope, and diversity

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

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

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

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

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

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

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

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

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

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

Operating efficiency

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

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

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

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

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

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

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

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

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

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

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

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

operating efficiency is generally otherwise considered adequate.

Profitability

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

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

Level of profitability

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

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

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

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

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

Volatility of profitability

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

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

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

Part II--Financial Risk Analysis

D. Accounting

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

Accounting characteristics

55. Some important accounting practices for utilities include:

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

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

Purchased power adjustment

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

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

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

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

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

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

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

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

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

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

66. Adjustment procedures:

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

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

debt.

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

Natural gas inventory adjustment

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

68. Adjustment procedures:

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

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

Securitized debt adjustment

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

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

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

71. Adjustment procedures:

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

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

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

Infrastructure renewals expenditure

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

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

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

74. Adjustment procedures:

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

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

E. Cash flow/leverage analysis

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

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

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

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

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

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

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

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

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

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

Part III--Rating Modifiers

F. Diversification/portfolio effect

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

G. Capital structure

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

H. Liquidity

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

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

I. Financial policy

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

J. Management and governance

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

K. Comparable ratings analysis

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

Appendix--Frequently Asked Questions

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

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

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

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

What is your definition of regulatory jurisdiction?

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

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

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

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

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

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

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

RELATED CRITERIA AND RESEARCH

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

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

DESCRIPTION OF BOND RATINGS

Categories	Moody's (1)	Standard & Poor's/Fitch	Definition
High Grade	Aaa	AAA	The highest rating, indicating an extremely strong capacity to pay principal and interest
	Aa	AA	Strong capacity to pay principal and interest. Margins of protection are less strong than those for Aaa and AAA bonds
Medium Grade	A	A	Favorable investment attributes, but elements may suggest a susceptibility to impairment given adverse economic changes
	Baa	BBB	Adequate capacity to pay principal and interest, but certain protective elements may be lacking that could lead to a weakened capacity for payment.
Speculative	Ba	BB	Bonds regarded as having only moderate protection
	B	B	Assurance of interest and principal payments over any long period of time may be small.
Default	Caa	CCC	May be in default or in danger of default.

[1] S&P and Fitch further differentiate ratings by using +’s and –‘s within each category and Moody’s uses a numbering system of 1, 2 and 3 within each category where 1 is the most favorable.

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Corporate Methodology: Ratios And Adjustments

*(**Editor's Note:** We originally published this criteria article on Nov. 19, 2013. We republished this article on Oct. 31, 2014, to clarify a term in paragraph 104. We republished this article following our periodic review completed on Oct. 16, 2014. We republished this article to add a section on frequently asked questions. We republished this article on April 10, 2014, to correct the first bullet point in paragraph 174 regarding the lease disclosure requirements under International Financial Reporting Standards, and the second bullet point in the same paragraph to add that CFO, as well as FFO, are increased by adding back the depreciation expense. These corrections have no impact on our ratings.)*

1. Standard & Poor's Ratings Services is updating its criteria for making analytical adjustments to companies' financial data, following its "Request for Comment: Corporate Criteria: Ratios And Adjustments," published on June 26, 2013, on RatingsDirect. This criteria update relates to our global corporate criteria "Corporate Methodology," published on Nov. 19, 2013, and to the criteria article "Principles Of Credit Ratings," published on Feb. 16, 2011.

2. This criteria article supersedes "2008 Corporate Criteria: Ratios And Adjustments," published on April 15, 2008, and other articles, as listed in the Appendix.

I. SCOPE OF THE CRITERIA

3. These criteria apply to nonfinancial corporate entities we rate globally. It excludes project finance entities and corporate securitizations because of their unique characteristics.

II. SUMMARY OF THE CRITERIA

4. The analytical adjustments that Standard & Poor's makes to the reported financial results of companies worldwide allow for globally consistent and comparable financial data.

5. These adjustments also enable better alignment of a company's reported figures with our view of underlying economic conditions. Moreover, they allow a more accurate portrayal of a company's ongoing business, for example, following acquisitions or disposals, through pro forma adjustments.

6. There are general analytical adjustments that apply across multiple industries, but some are industry specific. The general adjustments are described in this criteria article, whereas the details of industry-specific adjustments are in the relevant criteria articles, labeled "Key Credit Factors."

III. IMPACT ON OUTSTANDING RATINGS

7. The impact of the new corporate criteria on ratings is described in the criteria article "Corporate Methodology," published on Nov. 19, 2013.

IV. EFFECTIVE DATE AND TRANSITION

8. These criteria are effective immediately.

V. METHODOLOGY AND ASSUMPTIONS

A. Reasons For Analytical Adjustments

9. A company's financial statements are the starting point of our financial analysis. Our analysis of a company's financial statements begins with a review of the accounting features to determine whether the data in the statements accurately measure a company's performance and position relative to that of its peers and the larger universe of corporate entities.

10. Understanding accounting frameworks such as International Financial Reporting Standards (IFRS), U.S. generally accepted accounting principles (U.S. GAAP), and other local or statutory GAAP, is therefore crucial to our corporate rating methodology. It is equally important to understand the differences between the accounting standards and how those differences can affect the reporting of economically equivalent transactions.

11. Accounting rules often provide options for the treatment of certain items, making the comparison of data difficult, even among companies using the same accounting frameworks. Moreover, business transactions have become increasingly complex, and so have the related accounting rules and concepts, which often involve greater reliance on subjective estimates and judgments.

12. In addition, several fundamental shortcomings of reporting requirements could reduce the quality and quantity of information in financial statements. One example relates to recognition and measurement: What circumstances determine whether an item such as a special-purpose entity or a synthetic lease should be reflected on or off a company's balance sheet, and at what value? Another example concerns transparency: What should a company disclose about the nature of off-balance-sheet commitments, compensation arrangements, or related-party transactions?

13. To allow for globally consistent and comparable financial analyses, our rating analysis includes quantitative adjustments to companies' reported results. These adjustments also enable better alignment of a company's reported figures with our view of underlying economic conditions. Moreover, they allow a more accurate portrayal of a company's ongoing business, for example following acquisitions or disposals, through pro forma adjustments.

14. Although our adjustments revise certain amounts that companies report under applicable accounting principles, this does not imply that we challenge the company's application of those principles, the adequacy of its audit or financial reporting process, or the appropriateness of the accounting judgments made to fairly depict the company's financial position and results for other purposes.

15. Rather, the methodology seeks to address a fundamental difference between accounting and analysis. An accountant

puts figures together in the form of financial statements. An analyst, by definition, picks the numbers apart and considers the implications of their components as well as the reported totals. It is rarely possible to completely recast a company's financial statements (so we do not attempt to apply double-entry accounting), but adjustments improve the relevance and consistency of the financial ratios we use in our analysis.

B. How And When Adjustments Apply

16. Certain adjustments pertain broadly to all industries because they apply to many types of companies at all times. These include adjustments for operating leases and postretirement employee benefits. Other adjustments may pertain only to a certain industry. Industry-specific adjustments are in the relevant criteria articles labeled Key Credit Factors.

17. In rare circumstances, consistent with the principles underpinning our explicit adjustments, we may make nonstandard analytical adjustments to depict a transaction differently from the reported financial statements or simply to increase the comparability of financial data across industries. For example, we may treat certain cash-raising transactions as akin to borrowing if they do not follow the standard trade terms of an industry and are in lieu of conventional debt issuance.

18. Our use of analytical adjustments depends on whether events and items a company reports could have a material impact on our view of the company's creditworthiness. Therefore, we may not make certain adjustments if the related amounts are too small to be material to our analysis.

19. Additionally, the transparency or extent of a company's disclosure in its financial statements may preclude adjustments to reported figures. For example, in many industries there is insufficient disclosure to allow full adjustments to income for inventory figures that reflect the "last in first out" valuation method.

C. Adjusted Debt Principle

20. Many of the analytical adjustments we make result from our view of certain implicit financing arrangements as being debt-like. Our depiction of these transactions as debt, which is often contrary to how a company reports them, affects not only the quantification of debt but also the measures of earnings and cash flows we use in our analysis. Therefore, it is instructive to understand the principles underpinning our adjustments to debt.

21. In general, items that we add to reported debt include:

- Incurred liabilities that provide no future offsetting operating benefit (such as unfunded postretirement employee benefits and self-insurance reserves);
- On- and off-balance-sheet commitments for the purchase or use of long-life assets (such as lease obligations) or businesses (such as deferred purchase consideration) where the benefits of ownership are accruing to the company; and
- Amounts relating to certain instances when a company accelerates the monetization of assets in lieu of borrowing (such as through securitization or factoring of accounts receivable).

22. Many of the items that increase debt under the adjustments are probable future calls on cash, but not all future calls on

cash are forms of debt. We do not consider a company's future commitments to purchase goods or services it has not received as akin to debt. This is because these are executory contracts, which means a counterparty must still perform an action and the benefits of ownership have yet to accrue to the company.

23. Not all incurred liabilities are added to reported debt. The adjusted debt figure excludes short-term obligations, such as accounts payable and other accrued liabilities, because we regard them as trade credit rather than the incurrence of long-term debt. However, to the extent that a company defers payment beyond the term customary for its supply chain, we may add that amount to debt.

24. Additionally, we may exclude certain obligations a company reports as debt. This is, for example, because we perceive those obligations as equity rather than debt.

25. Companies' recognition and measurement of the numerous financing mechanisms vary. Some are reported at amortized cost (for example, issued debt), others at fair value (such as for contingent consideration), and others somewhere in between (as for pension obligations). Companies may also exclude certain financing from the balance sheet (such as operating leases). Ideally, we add to reported debt the amounts that approximate the amortized cost of commitments we consider to represent a debt, although from a practical standpoint this is not always possible.

26. Lastly, we may reduce the adjusted debt figure by netting surplus cash (see paragraphs 231-238).

D. Financial Ratios

27. The components of our ratios are derived from figures in companies' financial statements, subject to adjustments (subsequently referred to as "all applicable adjustments") defined in this criteria article and in the applicable Key Credit Factors articles. The definitions of the components are in the glossary (see paragraphs 248-263).

E. Analytical Adjustments

28. To calculate our financial ratios, we may make analytical adjustments related to the following:

- 1. Adjusted debt and interest

a) Accrued interest and dividends

b) Debt issuance costs

c) Debt at fair value

d) Fair-value hedging

e) Convertible debt

f) Foreign currency hedges of debt principal

g) Initial measurement of debt

- 2. Asset-retirement obligations
- 3. Capitalized development costs
- 4. Capitalized interest
- 5. Financial and performance guarantees
- 6. Hybrid capital instruments
- 7. Inventory accounting methods
- 8. Litigation
- 9. Multi-employer pension plans
- 10. Nonoperating activities and nonrecurring items
- 11. Leases
- 12. Postretirement employee benefits and deferred compensation
- 13. Scope of consolidation
- 14. Securitization and factoring
- 15. Seller-provided financing
- 16. Share-based compensation expenses
- 17. Surplus cash
- 18. Workers' compensation and self-insurance

1. Adjusted debt and interest

29. In reflecting reported debt in our metrics, our objective is to use an amortized cost method, consistent with the amortized cost method under accounting standards like IFRS and U.S. GAAP. This method reflects debt as the amount of the original proceeds, plus interest calculated using the effective interest rate, minus payments of principal and interest. The effective interest rate is equivalent to the yield to maturity of a bond and takes into account the compounding of interest. This rate is consistent over the term of a fixed-rate debt instrument. For variable-rate debt, the effective interest rate after issuance will vary each time the coupon rate is reset. Under the amortized cost method, interest expense is measured at the full cost of the borrowing.

30. However, companies do not always report debt in this manner. Several factors can distort the measurement of debt, such as the exclusion of accrued and unpaid interest, the inclusion of debt-issuance costs, reporting debt at fair value, applying fair-value hedge accounting, and the method of accounting for convertible instruments. The use of different measures for debt may also result in interest expense amounts that differ from those under the amortized cost method. We make adjustments to the measurement of reported debt and interest in certain circumstances as described in paragraphs 31 to 70.

a) Accrued interest and dividends

31. We reclassify as debt any accrued interest that is not already included in reported debt. This adjustment enables a more consistent comparison among companies' financial obligations, by eliminating the disparity arising from differences in the frequency of interest payments (for example, quarterly rather than annually) or in payment due dates (for example, Jan. 1 or Dec. 31).

32. Additionally, we treat accrued interest or dividends on hybrid securities as debt. Deferred cumulative interest--whether the deferral was optional or mandatory--is also treated as debt.

Adjustment procedures

33. Data requirements:

- Reported accrued interest on debt, and dividends on hybrid securities, as of the balance-sheet date.

34. Calculations:

- Debt: Add to reported debt any accrued interest on debt and any dividends on hybrid securities.

b) Debt issuance costs

35. Debt issuance costs are a form of prepaid interest, which companies record on the balance sheet and amortize as an interest expense over the term of the debt. We regard them as part of the total cost of borrowing and therefore do not deduct the amortization of debt issuance costs from reported interest.

36. However, there are different approaches to where these amounts are reported on the balance sheet. A company may either report debt issuance costs as a separate asset, or deduct them from reported debt as a "contra liability" (that is, a liability with a debit balance, rather than the typical credit balance). We look to exclude these prepaid amounts from debt, when reported as a contra liability, to attain comparability. Similarly, if a company deducts premiums paid for modifications or redemptions from debt, we exclude those amounts from debt if practicable.

Adjustment procedures

37. Data requirements:

- Amount of debt issuance costs or modification premiums reported as a contra liability, which reduces reported debt.

38. Calculations:

- Debt: Add to reported debt the amount of debt issuance costs or modification premiums reported as a contra liability.

c) Debt at fair value

39. In certain circumstances, a company may report debt at fair value instead of at amortized cost. In such cases, we adjust the reported figure to reflect the amortized cost method. If the amortized cost figure is not shown in the financial statements, we may estimate it, based on the amount originally received or the face value plus accrued but unpaid interest.

40. In addition, we seek to exclude gains or losses from the revaluation of debt at fair value from our measure of interest expense. However, from a practical standpoint, if a company does not disclose these figures, it is difficult to adjust interest expense for the difference between the reported figure and the effective rate achieved by the amortized cost method.

41. When this difference is material, we may make estimates to arrive at a figure that approximates interest expense, exclusive of mark-to-market effects. We would make such an estimate by, for example, multiplying the face value of the obligation by an interest rate estimated from other similar debt instruments.

Adjustment procedures

42. Data requirements:

- The amount of debt using the amortized cost method (from the financial statements) or, if this is not available, an estimate based on the amount originally received or the face value plus accrued but unpaid interest.
- The amount of any charge or benefit for debt reported at fair value and recorded as an interest expense.

43. Calculations:

- Debt: Increase or decrease reported debt by the difference between the reported amount and our estimate of the amortized cost.
- Interest expense: Increase or decrease reported interest expense by the amount of any charge or benefit for debt reported at fair value and recorded as an interest expense.

d) Fair-value hedging

44. A company may issue fixed-rate debt and at the same time enter a derivative contract to synthetically create a variable-rate debt instrument. If all necessary conditions are met, companies may elect to apply fair-value hedge accounting to such an arrangement. The effect of this accounting approach is that a company would report both the derivative instrument and the debt (but only the risk being hedged) at fair value. Changes in the fair values of both items from one reporting date to the next are netted off against each other in the income statement.

45. When a company applies fair-value hedge accounting to debt, we adjust the reported debt figure to reflect the amortized cost method.

46. It is not necessary to adjust interest expense in this case because the fair-value adjustments the company makes in the income statement generally offset each other, and settlements under the derivative are reported as an interest expense.

Adjustment procedures

47. Data requirements:

- The debt figure expressed as the amortized cost amount in the financial statements.
- If this is not available, we (1) determine the amount of the fair-value adjustment made to reported debt as a consequence of hedge accounting; or (2) estimate the adjustment amount using the fair value of the related derivative instrument; or (3) adjust debt to reflect the amount originally received as proceeds or the face value plus accrued and unpaid interest.

48. Calculations:

- Debt: Increase or decrease debt by the difference between the reported amount and our estimate of debt under the amortized cost method.

e) Convertible debt

49. Due to their complex nature, we take a slightly different approach to measuring convertible debt instruments that give the holder the option of converting the debt into shares. Because of this option, the coupon rate on such obligations is normally lower than market interest rates.

50. Under U.S. GAAP and IFRS the value of a convertible debt obligation is split into a debt component and an equity

component (following the split-accounting method).

51. The debt component is the fair value of a similar debt obligation without the conversion feature. This amount is accounted for under the amortized cost method and increases toward the face value of the convertible debt instrument until maturity or conversion.

52. The equity component (the value of the conversion feature) represents the difference between the debt component and the issue price of the convertible debt instrument. The value of the equity portion remains constant.

53. Although uncommon, we may regard a convertible debt instrument as having equity content in our analysis, depending on its terms and conditions and our view of the likelihood that the debt holder will convert it to equity (see "Hybrid Capital Handbook: September 2008 Edition," published on Sept. 15, 2008). If we consider such an instrument to have high equity content, we reclassify it as equity. If we consider that there is minimal equity content, we treat the instrument fully as debt.

54. We typically add to reported debt the unamortized value of the discount created by the conversion option, bringing the value of such an instrument back to par.

55. In our ratios, we seek to include the full effective cost of the obligation as interest. We believe the interest resulting from the split-accounting method achieves this goal and therefore no adjustment is necessary.

56. If a company does not use split accounting we estimate the cost of debt by increasing reported interest expense when the difference in value under the other method is material.

Adjustment procedures

57. Data requirements:

- The face value of convertible debt instruments or the remaining unamortized discount as of the balance-sheet date.
- The amount of interest expense reported in the period, if we consider the instruments to have high equity content.

58. Calculations:

- Debt: Increase reported debt by the amount necessary to bring an instrument back to par. If an instrument has high equity content according to our criteria, we deduct the reported amount from debt.
- Interest: Subtract from interest the amount of interest expense on convertible debt considered to have high equity content.

f) Foreign currency hedges of debt principal

59. Foreign-currency-denominated debt is typically included in consolidated debt on the balance sheet at the amount of foreign currency, translated at the spot rate on the balance-sheet date.

60. Many companies hedge the foreign currency exposure by entering into derivatives that fix the foreign exchange rate that will apply on the debt's repayment date. To better reflect the economics of such transactions, we adjust the reported amount of foreign-currency-denominated debt to reflect the net amount required for repayment as a result of the hedge.

61. We may not make this adjustment if other factors can neutralize the benefit of the derivative. These factors include

concerns about risk relating to the derivative counterparty (such as when a derivative counterparty has credit quality equivalent to 'BB+' or lower) and other derivative contracts that can offset the benefit of the derivative hedge.

62. The adjustment amount results from restating the hedged debt principal using the "locked-in" foreign exchange rate achieved through the derivative. The adjustment amount is broadly equivalent to the fair value of a derivative representing a foreign currency hedge of debt principal, but may differ for various reasons, such as because the derivative's fair value also reflects liquidity and counterparty risk.

63. We use the derivative's value as a proxy for our adjustment amount if retranslation of the debt balance is not practical because of insufficient information.

64. However, companies often hedge the foreign currency exposure related to debt principal and interest simultaneously. In this instance, we take care to adjust only for the fair value of the derivative that hedges the principal, and not the portion that hedges the interest.

Adjustment procedures

65. Data requirements:

- The amount of hedged foreign-currency-denominated debt (from the balance sheet); and
- The locked-in foreign exchange rate (or locked-in principal value of outstanding debt) achieved via the hedge transaction.
- Alternatively, the fair value of the derivative that applies only to the principal (that is, excluding any fair value associated with hedged interest payments).

66. Calculations:

- Debt: Retranslate foreign-currency-denominated debt using the locked-in foreign exchange rate (or adjust the balance-sheet value of debt to equal the locked-in principal value). Alternatively, add to or subtract from reported debt the fair value of the hedging instrument on the balance-sheet date.

g) Initial measurement of debt

67. We subscribe to amortized cost as the preferred method of measuring debt after debt is issued. However, in certain circumstances, we may take an alternative view toward a company's initial measurement, and therefore ongoing measurement, of a particular debt instrument, as described in the next paragraph.

68. Companies usually initially measure debt at an amount equal to the net proceeds received at issuance. However, there are other methods of initial measurement of debt that we believe can in certain instances distort the initial and ongoing carrying value of debt. This may include the methods applied to debt assumed in an acquisition, or debt that has been modified or is part of a distressed exchange. When our judgment about the initial measurement (and therefore ongoing measurement) of a debt instrument differs from a company's, we may adjust debt, funds from operations (FFO), and interest expense if practical and the effect is material.

Adjustment procedures

69. Data requirements:

- Initial measurement of the applicable debt instrument.

- Our assumed measurement of the applicable debt instrument.
- Interest expense associated with the applicable debt instrument that is reported during the period.
- Interest expense for the period, based on our assumed initial measurement of the applicable debt instrument.

70. Calculations:

- Debt: Increase or decrease debt by the difference between the reported amount of debt and our estimate of amortized cost based on our assumed initial measurement.
- Interest expense: Increase or decrease interest expense by the difference between reported interest expense and the estimated interest expense based on our assumed initial measurement.
- FFO: Increase or decrease FFO by the difference between reported interest expense and the estimated interest expense based on our assumed initial measurement.

2. Asset-retirement obligations

71. Asset-retirement obligations (AROs) are legal obligations associated with a company's retirement of tangible long-term assets. Examples of AROs include the cost of plugging and dismantling oil and gas wells, decommissioning nuclear power plants, and treating or storing spent nuclear fuel and capping and restoring mining and waste-disposal sites.

72. We treat AROs as debt-like obligations, although several characteristics distinguish them from conventional debt, including timing and measurement uncertainties.

73. A company's liability for AROs is independent from the amount and timing of the cash flows the associated assets generate. In certain situations, companies fund AROs by adding a surcharge to customer prices; or the AROs are paid by third parties, such as a state-related body. In these cases there would typically be no debt adjustment.

74. The measurement of AROs involves a subjective assessment and is therefore imprecise. We generally use the reported ARO figures, but we may make adjustments for anticipated reimbursements, asset-salvage value, or any of the company's assumptions we view as unrealistic. Those assumptions may include the ultimate cost of abandoning an asset, the timing of asset retirement, and the discount rate used to calculate the balance-sheet value.

75. Under most accounting standards, company balance sheets show the ARO figure before tax, and any expected tax benefits as a separate deferred tax asset on the balance sheet (because the associated ARO-related asset is subject to depreciation). Tax savings that coincide with settling ARO payments (as opposed to their provisioning), reduce the cash cost of the AROs, and we factor them into our analysis to the extent that we expect the company to generate taxable income in the same tax jurisdiction.

76. Our approach is to add AROs--after deducting any dedicated retirement-fund assets or provisions, salvage value, and anticipated tax savings--to debt. We generally adjust for the net aggregate funding position, even if some specific obligations are underfunded and others are overfunded. The adjustment amounts are tax effected (that is, adjusted for any tax benefit the company may receive) if the company will likely be able to use tax deductions.

77. The accretion of an ARO that reflects the time value of money is akin to noncash interest and similar to postretirement benefit interest charges. Accordingly, we reclassify the accretion (net of earnings on any dedicated funds), using a floor of zero for the net amount as interest expense, in analyzing the income and cash flow statements.

78. If dedicated funding is in place and the related returns are not entirely reflected in reported earnings and cash flows,

we add the unrecognized portion of the related returns to earnings and cash flows. We reclassify the recognized portion to interest expense and cash flow from operations (CFO).

79. We treat cash payments for the abandonment of assets and contributions to dedicated funds that exceed ARO interest costs (after deducting ARO fund earnings) as repayment of the ARO. We therefore add these amounts to FFO and CFO.

80. We treat cash payments for the abandonment of assets and contributions to dedicated funds that are less than the ARO interest costs (after deducting ARO fund earnings) as the incurrence of a debt obligation. We therefore deduct the shortfall in payments from FFO and CFO.

Adjustment procedures

81. Data requirements:

- The ARO figure (from the financial statements or Standard & Poor's estimate).
- Any associated assets or funds set aside for AROs.
- ARO interest costs irrespective of whether charged to operating or financing costs.
- The reported gain or loss on assets set aside for funding AROs.
- Any cash payments for AROs.

82. Calculations:

- Debt: Add net ARO to debt (net ARO equals the reported or estimated ARO minus any assets set aside to fund AROs, multiplied by 1 minus the tax rate).
- EBITDA: Add ARO interest costs included in operating costs.
- Interest: Deduct ARO interest costs (net of ARO fund earnings) from reported operating expenses, if included there, and add to interest expense.
- FFO: Our definition of FFO is EBITDA minus net interest expense minus current tax expense, after adjusting each of the three components according to our criteria. EBITDA and interest expense are adjusted as described in the previous two bullet points. The figure to adjust the current tax expense results from multiplying the applicable tax rate by the net result of (1) new provisions, plus (2) interest costs, minus (3) the actual return on funded assets, minus (4) fund contributions or ARO payments in the corresponding period. The net effect of these adjustments is that FFO is reduced by net ARO interest and adjusted for tax effects.
- CFO: Subtract the gain (or add the loss) on assets set aside for AROs from interest expense. Then compare the resulting amount with payments on the AROs to arrive at the excess contribution or shortfall to add to, or subtract from, CFO. Additionally, we adjust CFO for tax effects in a similar way as for FFO.

3. Capitalized development costs

83. In financial reporting, research costs are almost universally treated as an expense; however the treatment of development costs varies. U.S. GAAP, with limited exceptions (such as for software development costs in certain instances), requires companies to treat development costs as an expense, whereas IFRS allows such costs to be capitalized under certain conditions. In addition to these differences between accounting regimes, there is an element of subjectivity in determining when development costs are capitalized, which can lead to a disparity among companies' reported figures.

84. To enhance the comparability of data, we adjust reported financial statements when a company capitalizes

development costs, if the information is available and the amounts material. The adjustment aims to treat the capitalized development costs as if they had been expensed in the period incurred.

85. We aim to adjust EBITDA, FFO, and CFO for the amount of development costs capitalized during the year. This is because a company's position in its product life cycle has a great effect on its current spending relative to the amortization of previously capitalized development costs. However, in the absence of accurate figures, we use the annual amortization figure reported in the financial statements as a proxy for the current year's development costs. To the extent that the amortization of previously capitalized costs equals current development spending, there is no impact on operating expenses and EBIT because these amounts are after amortization. However, there is an impact on EBITDA, FFO, and CFO, which are calculated before amortization.

86. We do not carry through the adjustment to the cumulative asset (and equity) accounts, weighing the complexity of such adjustments against their typically limited impact on amounts that are secondary to our analysis.

87. We make one exception to this approach, and that is for capitalized development costs relating to internal-use software. Consistent with our goal of achieving comparability, we do not want to create a gap between companies that develop software for internal use and those that purchase software and capitalize equivalent products. We therefore attempt to exclude such costs from our adjustment.

Adjustment procedures

88. Data requirements:

- Amount of development costs incurred and capitalized during the period, excluding, if practical, capitalized development costs for internal-use software.
- Amortization amount for relevant capitalized costs.

89. Calculations:

- EBITDA, FFO, and CFO: Subtract the amount of net capitalized development costs or, alternatively, the amortization amount for that period.
- EBIT: Subtract (or add) the difference between the spending and amortization in the period.
- Capital expenditures: Subtract the amount capitalized in the period.

4. Capitalized interest

90. Under most major accounting regimes, financial statements show interest costs related to the construction of fixed assets as capitalized, that is, as a component of the historical cost of capital assets. This can obscure the total interest that has been incurred during the period, hindering comparisons of the interest burden of companies that capitalize and do not capitalize interest.

91. Under our methodology, interest costs that have been capitalized are adjusted and included as interest expense in the period in which the interest was incurred.

92. In the statement of cash flows, we reclassify any capitalized interest shown as an investing cash flow to operating cash flow. This adjustment reduces CFO and capital expenditures by the amount of interest capitalized in the period. Free operating cash flow remains unchanged.

93. We make no adjustment for the cumulative effect on the value of property, plant, and equipment resulting from any prior-year interest capitalization, tax effects, or depreciation, due to disclosure limitations and the minimal analytical benefit this would provide.

Adjustment procedures

94. Data requirements:

- The amount of capitalized interest during the period.

95. Calculations:

- Interest expense: Add amount of interest capitalized during the period.
- FFO: Our definition of FFO is EBITDA minus net interest expense minus current tax expense, after adjusting each of the three components according to our criteria. Net interest expense includes the interest capitalized during the period, as described in the previous bullet point. Therefore, FFO is reduced by the amount of interest capitalized in the period.
- CFO: Subtract the amount of capitalized interest recorded as an investing cash flow.
- Capital expenditures: Subtract the amount of capitalized interest recorded as an investing cash flow.

5. Financial and performance guarantees

a) Financial guarantees

96. A financial guarantee is a promise by one party to assume a liability of another party if that party fails to meet its obligations under the liability. A guarantee can be limited or unlimited. If a company has guaranteed liabilities of a third party or an unconsolidated affiliate, we may add the guaranteed amount to the company's reported debt.

97. We do not add the guaranteed amount to debt if the other party is sufficiently creditworthy (that is if the other party has credit quality equivalent to 'BBB-' or higher) in its own right, or we believe that the net amount payable if the guarantee were called would be lower than the guaranteed amount. This could happen, for example, if the company that has provided the guarantee has been counter-guaranteed by another party. In this case, we add the lower amount to debt. We do not adjust interest expense because the guarantor is only obliged to service interest if called upon to meet the guarantee.

b) Performance guarantees

98. A performance guarantee is a promise to provide compensation if a company does not complete a project or deliver a product or service according to the agreed terms. An insurance company or bank may issue such guarantees on a company's behalf. Construction companies often provide performance guarantees to meet a condition in a work contract. If the project, product, or service is not completed as agreed, the customer can call on the performance guarantee.

99. We do not regard performance guarantees as debt if a company is likely to maintain sufficient work or product quality to avoid making large payments under those guarantees.

100. A company's past record of payments under performance guarantees could indicate the likelihood of future payments under such guarantees. Only if this payment history suggests a high likelihood of future payments would we estimate a potential liability and add that amount to debt.

Adjustment procedures

101. Data requirements:

- The value of guarantees on and off the balance sheet, net of any tax benefit.

102. Calculations:

- Debt: Add to debt the amount of on- and off-balance-sheet debt-equivalent related to guarantees, net of any tax benefit.
- Equity: Subtract from equity the amount of off-balance-sheet debt-equivalent related to guarantees, net of any tax benefit.

6. Hybrid capital instruments

103. Hybrid capital instruments (or hybrids) have features of both debt and common equity. We classify a corporate hybrid as having minimal, intermediate, or high equity content depending on the specific terms and conditions of the instrument and our view of whether the issuer intends to maintain the instrument as loss-bearing capital. Our classification of equity content determines the type of adjustments we make to a company's reported figures.

104. A company's issuance of conventional hybrids, in an aggregate amount of up to 15% of capitalization, can be eligible for equity credit, which means that we exclude at least some of the hybrid instrument and its interest costs from our debt and interest measures (see "Hybrid Capital Handbook: September 2008 Edition," published on Sept. 15, 2008). We exclude bonds that are mandatorily convertible into shares from this calculation. Capitalization is equal to balance-sheet equity, plus debt and hybrids, after adjusting for goodwill and making all applicable adjustments. The capitalization calculation excludes any goodwill asset that exceeds 10% of total assets.

105. The treatment of hybrids for the purposes of our leverage and debt service ratio calculations depends on the equity content classification:

- Hybrids that have high equity content are treated as equity and the interest or dividends are treated as dividends.
- For hybrids with intermediate equity content, 50% of the principal is treated as debt and 50% as equity (excluding unpaid accrued interest or dividends, which are added to debt). Similarly, we treat one-half of the period's interest or dividends as dividends and one-half as interest. There is no adjustment to related taxes.
- Hybrids with minimal equity content are treated entirely as debt and all interest or dividends as interest.

106. In all cases, accrued coupon payments are treated as debt.

107. The criteria for adjustments related to convertible debt are in paragraphs 49-58 of this article and in "Hybrid Capital Handbook: September 2008 Edition," published on Sept. 15, 2008.

Adjustment procedures

108. Data requirements:

- Documentation for reported hybrid capital instruments.
- Amount of hybrids, debt, goodwill, and shareholders' equity on the balance sheet.
- Amount of associated interest or dividend expense and interest or dividend payments in the period.
- Amount of accrued unpaid interest or dividends.

109. Calculations:

- Hybrids reported as equity: (1) If we classify equity content as high, there is no adjustment to equity. (2) If we classify equity content as intermediate we deduct 50% of the value from equity and add it to debt. We also deduct 50% of the dividend accrued during the accounting period and add it to interest expense, thereby reducing FFO. Likewise, 50% of any dividends paid are deducted from CFO. (3) If we classify equity content as minimal, we deduct the full principal amount from equity and add it to debt. We add associated dividends to interest expense, thereby reducing FFO. Likewise dividends paid are added to interest paid, thereby reducing CFO.
- Hybrids reported as debt: (1) We deduct the value of hybrids with high equity content from debt and add it to equity. We also deduct the associated interest charge from interest expense and add it to dividends, thereby removing it from FFO. Likewise, interest paid is added to CFO and dividends. (2) If we classify equity content as intermediate, we deduct 50% of its value from debt and add it to equity. We also deduct 50% of the associated interest expense from interest expense and add it to dividends accrued, thereby increasing FFO. 50% of interest paid is added to CFO. (3) If equity content is minimal there is no adjustment because we treat such hybrids as debt.
- Debt: We add to debt the accrued and unpaid interest and dividends on all hybrids.

7. Inventory accounting methods

110. Accounting frameworks allow companies a choice of inventory accounting method, and this leads to reporting differences within industries and among regions. The disparity is more pronounced in inventory-intensive industries, particularly when the price of inventory (such as raw materials) fluctuates significantly. This is because the method a company uses influences the amount of inventory it can charge as an expense, and therefore also its taxable income. The inventory accounting methods under U.S. GAAP are "first in first out" (FIFO), "last in first out" (LIFO), weighted-average cost, and specific identification.

111. Similar costing methods exist in other generally accepted accounting principles. However, many frameworks, including IFRS, do not allow LIFO. The tax treatment is a key factor in a company's choice of inventory costing method and it varies significantly by jurisdiction. For example, LIFO is permitted for tax-reporting purposes in the U.S., and a company that uses it for tax purposes must also use it for preparing its financial statements.

112. The greatest potential disparity in financial results comes from using FIFO as opposed to LIFO. When inventory prices are rising, the LIFO method results in lower income than under FIFO because the most recent and higher cost of goods is transferred to the income statement, while the remaining inventory is shown at the older, lower cost on the balance sheet. Furthermore, LIFO results in improved cash flows for that period because income taxes are lower as a result of the lower taxable income.

113. Apart from hindering comparison between different companies, the different methods can also obscure a company's true performance record. For example, LIFO arguably allows for a more realistic depiction of current costs on the income statement, but showing inventory at older costs distorts the balance-sheet position. The FIFO method, on the other hand, provides a more up-to-date valuation of inventory on the balance sheet, but can significantly understate the cost of goods sold during a period of rising prices and overstate income.

114. We adjust the reported inventory figures if material to our analytical process. Companies that use LIFO have to disclose what the inventory valuation would be under FIFO, through an account called the LIFO reserve that represents the cumulative effect on gross profit from the use of the LIFO method. For such companies, we add the

balance in the LIFO reserve to the reported inventory. This enables us to reflect inventory balances at approximately the current market value. A corresponding adjustment, net of tax, is made to equity.

115. We do not adjust the income statement when a company uses LIFO because we believe the LIFO method results in costs of goods sold that closely reflect replacement-cost values.

116. Typically, there are no adjustments to the income statement for companies that use FIFO or the average cost method because the data are generally not available.

117. When a company using the LIFO method has inventory balances that decrease over a period of time, LIFO liquidation may result. This means that older layers of inventory are turned into cost of goods sold as a result ("older" refers to inventory in terms of their accounting and not necessarily in a physical sense). Assuming an inflationary environment, the cost of goods sold is reduced and, as a result, income increases because of LIFO liquidation gains. To capture the true sustainable profitability of a company, we generally exclude the gains generated from LIFO liquidation from our profitability measures.

Adjustment procedures

118. Data requirements:

- The balance of the LIFO reserve account.
- LIFO liquidation gains from the income statement.

119. Calculations:

- Assets: Add the LIFO reserve to inventory.
- Equity: Add the LIFO reserve (after tax) to equity.
- EBITDA, EBIT, and FFO: Deduct LIFO liquidation gains from EBITDA, EBIT, and FFO.

8. Litigation

120. If a company is a defendant in a major lawsuit, we may adjust its debt to account for the potential cost when an adverse outcome (payment of a cash settlement or damages) is probable or has materialized. If the estimated or known amount of the potential payment is material in relation to the company's cash flow or leverage ratios, we add that figure to reported debt. Before doing so, we may reduce the potential payment to reflect the expected reimbursement from legal insurance coverage, cash held in reserve, and extended payment dates; or add accruing interest penalties.

121. The adjusted debt figure therefore includes the present value of the net estimated payout, on an aftertax basis.

122. To achieve the difficult task of sizing the litigation exposure, we may use as a reference any resolved lawsuits that can serve as benchmarks. We also consider the company's reported litigation reserves and the different thresholds for their recognition under IFRS and U.S. GAAP.

123. Because the full financial effects of a lawsuit are difficult to quantify accurately, the analysis also involves techniques such as calculating ranges of outcomes or performing a sensitivity analysis. The results of these techniques can indicate, for example, what effect even higher potential payouts would have on a company's financial profile.

124. If, to allow for a possible adverse financial judgment, a company has placed cash in escrow with the courts or is

expected to do so; or if it had to provide a financial guarantee to the courts, we incorporate the impact of this actual or contingent commitment into the liquidity assessment.

Adjustment procedures

125. Data requirements:

- An estimate or actual amount of the litigation exposure.

126. Calculations:

- Debt: Add the estimated or actual amount of litigation exposure (net of any applicable tax deduction) to reported debt.
- Equity: Subtract the amount of estimated litigation exposure considered to be debt-like that exceeds the accrued litigation exposure, if any.

9. Multi-employer pension plans

127. Some companies in the U.S. participate in multi-employer, defined-benefit pension plans on behalf of their employees. Such companies are predominantly in the transportation, building, construction, manufacturing, hospitality, and grocery sectors. The pension plans are often are referred to as "Taft-Hartley" plans because they fall under the Taft-Hartley Labor Act (officially termed the "The Labor Management Relations Act") of 1947.

128. A multi-employer pension plan is forged by a collective bargaining agreement between companies that generally operate in the same sector and the union(s) that represent the sector's workers. These arrangements share many of the attributes of single-employer plans.

129. We regard the liability associated with a funding deficit on multi-employer pension plans as debt, as we do deficits on single-employer defined-benefit, postretirement obligations. For practical reasons, and because of a lack of pertinent data, we generally do not adjust cash flow measures in our analysis unless significant catch-up contributions are made; nor do we generally adjust our profitability measures.

a) Unique characteristics of multi-employer pension plans

130. Multi-employer pension plans pose some unique challenges, mainly because they are complex, and information about them in companies' financial statements is limited. For example, unlike for single-employer plans, there is generally no information on a company's potential share of a shortfall under a multi-employer plan, unless that company is withdrawing from the plan. Further, because the plans are collective, the sponsoring companies may become liable beyond their otherwise pro rata share of the obligation if another company becomes insolvent.

131. These challenges make it difficult to estimate the amount each company might have to pay to meet current and future obligations under such plans. It is therefore crucial to gather additional information that is timely and relevant, including the specific features of the plan and the collective bargaining process.

132. A company participating in a multi-employer plan faces problems that a company sponsoring a single-company pension plan does not, in particular if it wants to withdraw from such a plan. Companies that withdraw from an underfunded multi-employer plan may incur a withdrawal liability representing their pro rata shares of the total underfunded pension obligation. Determining the withdrawal liability amount accurately is difficult because statutes

provide several different ways to calculate it. Moreover, special rules in certain industries (such as construction, entertainment, and trucking) determine the withdrawal liability trigger points and the size of the obligation. For example, the withdrawal liability may be limited in cases such as a bona fide sale of substantially all of the employer's assets or the company's liquidation or dissolution.

133. A solvent company that exits an underfunded multi-employer pension plan generally continues to make payments for its share of the liabilities for as many years as the Employee Retirement Income Security Act specifies. However, if a company is insolvent, the other participating companies must assume all of its obligations. For single-employer plans, the sponsoring company is liable only for the underfunded portion of its own plan.

134. All of these factors make it difficult to estimate the amount of a company's potential liability under a multi-employer plan to add as debt. To do so, we consider the facts and circumstances associated with the plan. For example, instead of a pro rata share of the collective obligation, we may estimate a lower amount if we view it as plausible that the plan's trustees could reduce the plan's total liability over time by decreasing the level of future employee benefits. We primarily base this determination on information from the company and publicly available data.

b) Accounting and disclosure limitations

135. Under U.S. GAAP and IFRS, a company's withdrawal liability must be both probable and estimable for it to be recognized as a contingent liability in the financial statements. This obligation is therefore seldom accrued or disclosed.

136. Financial statement disclosure on multi-employer plans is typically limited to the significant plans an employer participates in, the company's annual contributions to each plan over the previous three years, and the relative financial health of the plans as indicated by regulatory guidelines.

137. Using publicly available tax and regulatory filings to approximate the funded status of a multi-employer pension is also problematic, considering filing delays. Plans must file Form 5500 (Annual Return/Report of Employee Benefit Plan) with the U.S. Department of Labor. This form provides useful data about a plan's overall financial health, its funding status, number of participants, and contribution levels. However, the form must be filed within 210 days after the end of the plan year (subject to a 75-day extension), and there may be an additional time lag before the Department of Labor publishes the information. The resulting data will therefore be somewhat out of date. In particular, in the period before the publication of the data, fluctuations in discount rates, market returns, and the terms of collective bargaining agreements, participation levels, and other actuarial assumptions may result in changes in the financial health of the plan that the filings do not reflect.

Adjustment procedures

138. Data requirements: Where material, obtain an estimate of the withdrawal liability for each plan a company participates in. If this figure is unavailable, we make an estimate of the company's pro rata share of the funded status based on the following information:

- The funded status of each of the multi-employer plans to which the company contributes. This information may be provided by the company for more recent years, or it may be obtained from the publicly available Form 5500s filed with the Department of Labor. To estimate the funded status, we use the Retirement Protection Act of 1994 liability, minus the fair value of assets as of the same date.

- The company's contributions to each of its multi-employer plans in the corresponding years.
- The total contributions to the multi-employer pension plan by all employers in the corresponding years.
- An applicable haircut for anticipated negotiations.

139. Calculations:

- Debt: Add the estimated withdrawal liability for all plans, net of tax, to debt. Alternatively, if not available, add to debt the estimate of the employer's share of the funded status of each plan (net of any applicable haircut and net of tax).

10. Nonoperating activities and nonrecurring items

140. We define our key income-statement-based metrics (EBITDA, EBIT, and FFO) in a particular fashion. However, the reported financials often do not conform to our views. Therefore it is necessary for us to adjust the reported financial information so that they fit in with our methodology.

a) Operating versus nonoperating items

141. Our decision to include or exclude an activity from a particular metric depends on whether we consider that activity to be operating or nonoperating in nature (see paragraphs 142-158). Independent of that decision, we consider whether an activity is recurring or nonrecurring (see paragraphs 159-164).

142. Our EBIT measure is a traditional view of profit that factors in capital intensity. We consider all income statement activity integral to EBIT, with the exception of interest and taxes. This includes all activity we consider nonoperating that is excluded from EBITDA.

143. Our definition of EBITDA is: Revenue minus operating expenses plus depreciation and amortization (including noncurrent asset impairment and impairment reversals). We include cash dividends received from investments accounted for under the equity method, and exclude the company's share of these investees' profits. This definition generally adheres to what EBITDA stands for: earnings before interest, taxes, depreciation, and amortization. However, it also excludes certain other income statement activity that we view as nonoperating.

144. Our definition of EBITDA aims to capture the results of a company's core operating activities before interest, taxes, and the impact on earnings of capital spending and other investing and financing activities. This definition links to the cash flow statement because we use EBITDA to calculate FFO, which we use as an accrual-based proxy for CFO (cash flow from operations).

145. Generally, this means that any income statement activity whose cash effects have been (or will be) classified as being from operating activities (excluding interest and taxes) are included in our definition of EBITDA.

146. Conversely, income statement activity whose cash effects have been (or will be) classified in the statement of cash flows as being from investing or financing activities is excluded from EBITDA.

147. We may however take alternative views about the classification of transactions to that presented in the statement of cash flows, and this would flow through to our other metrics.

148. Below are examples of how we apply this principle to various scenarios.

149. ***Disposals:-*** Under accounting standards, proceeds from the sale of a subsidiary are classified in the statement of cash flows as an investing cash flow rather than an operating cash flow. Moreover, we view the disposal of a subsidiary as outside core business operations. As such, we do not treat a gain or loss from the sale of a subsidiary as an operating activity and exclude this from our calculation of EBITDA and FFO.

150. The same rationale holds for the sale of property, plant, and equipment. The cash flows arising from such transactions are classified, under accounting standards, as investing activities in the statement of cash flows. Therefore, we would typically view any gains or losses on the sale of property, plant, and equipment as nonoperating items.

151. ***Restructuring costs:-*** We include restructuring costs in our calculation of EBITDA, consistent with their treatment in the cash flow statement as operating activities. Moreover, most companies need to restructure at some point, as the global economy is constantly evolving and businesses alter their operations to remain competitive and viable.

152. ***Acquisition-related costs:-*** These include advisory, legal, and other professional and administrative fees related to an acquisition. We include them in EBITDA, consistent with their treatment in the statement of cash flows as operating activities. Many businesses make acquisitions as part of their growth strategy; therefore it is important to factor these expenses into our metrics.

153. ***Asset impairments/write-downs:-*** Impairments on tangible and intangible noncurrent assets are akin to depreciation or amortization in that they represent a company's income-statement recognition of earlier capital expenditures. We therefore exclude them from our definition of EBITDA. Our definition of EBIT includes impairment charges or reversals. Our decision to exclude an impairment cost or reversal from EBIT would depend on whether we consider it to be recurring or nonrecurring (see paragraphs 159-164).

154. However, impairments on current assets, such as inventory and trade receivables, are included in our calculation of EBITDA. The charges for inventory represent a company's recognition in the income statement of cash that it has already spent, and those for trade receivables represent the reduction of income previously recognized, but which the company will not fully collect.

155. ***Unrealized gains or losses on derivatives:-*** If a company has not achieved the requirements of technical hedge accounting (even though an effective economic hedge may exist), it reports all mark-to-market gains or losses related to the fair-valuing of derivative contracts in the income statement. Although the nature of the underlying activity is often integral to EBITDA, FFO, or both, using mark-to-market accounting can distort these metrics because the derivative contract may be used to hedge several future periods.

156. Therefore, when we have sufficient information, we exclude the unrealized gains or losses not related to current-year activity, so that the income statement represents the economic hedge position achieved in the current financial year (that is, as if hedge accounting had been used). This adjustment is common in the utilities and oil and gas sectors.

157. ***Foreign currency transaction gains and losses:-*** Foreign currency transaction gains or losses arise from transactions denominated in a currency other than a company's functional currency (generally the currency in which it transacts most of its business). Examples include selling goods at prices denominated in a foreign currency, borrowing or lending in a foreign currency, or other contractual obligations denominated in a foreign currency.

158. Currency transaction gains and losses may be viewed as operating or nonoperating in nature. If gains or losses included in operating profit are operating in nature, we do not make adjustments. We may however adjust reported operating results for currency gains and losses that are nonoperating. For example, we may adjust (or exclude) foreign currency gains or losses resulting from the issuance of foreign-currency-denominated debt.

b) Nonrecurring items and pro forma figures

159. The relative stability or volatility of a company's earnings and cash flow is an important measure of credit risk that is embedded in our corporate criteria. For this reason, our use of nonrecurring or pro forma adjustments is limited to the extent that there has been some transformative change in a company's business. Examples of such changes are the divestment of part of the business or a fundamental change in operating strategy.

160. ***Discontinued operations and business divestments:-*** Companies typically segregate their profits or losses from discontinued operations from those of the continuing business; although the segregation of related cash flows is less consistent. We typically exclude profits, losses, and cash flows from discontinued operations from our metrics so that they more accurately reflect the company's ongoing operations.

161. ***Pro forma accounts for intrayear acquisitions or irregular reporting periods:-***If an acquisition has taken place, the financial statements for the year of the acquisition include all the debt of the enlarged group in the year-end balance sheet, but less than the full year's results and cash flows of the enlarged group. This distorts debt-coverage ratios, which therefore do not accurately indicate the company's likely future performance.

162. A similar issue exists when companies have irregular accounting periods, such as after a change in their accounting year-end. In these cases, we may use pro forma financial statements to allow for a more representative measure of full-year performance and more meaningful ratios.

163. ***Asset impairments and write-downs:-*** We generally exclude impairment charges on long-life assets from our measure of EBIT if they are very large and irregular. Excluding a nonrecurring impairment from EBIT produces a better estimate of a company's ongoing profitability, but does not mean we ignore the impairment in our analysis. On the contrary, a significant impairment may indicate that a company's ability to generate future cash flows has diminished.

164. We rarely exclude impairments of operating assets, such as inventories and receivables, from our EBITDA and FFO metrics because we wish to capture this volatility. An exception might be a genuine nonrecurring impairment, such as inventory impairment resulting from damage caused by a fire.

Adjustment procedures

165. Data requirements:

- Amounts of income, expense, and cash flows to be reclassified. The amounts are based on our analytical judgment, using information from the company and our assessments.

166. Calculations:

- Add or subtract amounts from the respective measures--such as, revenue, operating income before and after depreciation and amortization (D&A), D&A, EBIT, EBITDA, CFO, and FFO--and reclassify them according to our view of the underlying activities.
- Because CFO and FFO are aftertax measures, they are also adjusted to reflect tax effects, where feasible.

167. Beyond the standard adjustment, additional insights may be gleaned by adjusting individual line items within cost of goods sold or selling, general, and administrative expense, if there is sufficient data to reflect adjustments at such levels.

11. Leases

168. Companies commonly use leases as a means of financing, and the accounting method for leases distinguishes between operating and finance leases. Finance leases (also known as capital leases) are accounted for in a manner similar to a debt-financed acquisition of an asset and as a balance-sheet liability. Conversely, many operating leases are not accounted for as a balance-sheet liability, but the lease cost is recorded in the profit and loss account in each accounting period.

169. We view this accounting distinction as substantially artificial because under both types of lease arrangements, a company signs a contract that allows it to use an asset, thereby entering into a debt-like obligation to make periodic rental payments.

170. For this reason, we treat operating and finance lease obligations as debt. Reclassifying leases as debt seeks to enhance comparability between companies that finance assets using operating or financing leases and those that do so by incurring debt to finance the purchase of the asset. This adjustment aims to bring companies' financial ratios closer to the underlying economics and to make them more comparable by taking into consideration all of a company's financial obligations, whether on or off the balance sheet.

171. The methodology does not replicate a scenario in which a company finances the acquisition of an asset with debt. Rather, the adjustment is narrower in scope: It attempts to capture only a debt-equivalent for a company's lease contracts. For example, when a company enters into a five-year lease for an asset with a 20-year productive life, the adjustment includes only payments relating to the contracted five-year lease period. We do not use alternative methodologies that fully capitalize the value of the asset, given disclosure and other limitations.

172. However, if we view the term of a lease as artificially short relative to the length of expected use of the leased asset, we may make adjustments to reflect a more economically appropriate depiction of the underlying lease obligation. An example of this approach is for sale-and-leaseback transactions, where if practical we capitalize the entire sale amount.

Adjustment procedures

173. Data requirements:

- Minimum lease payments: The schedule of noncancellable future lease payments over the next five years and beyond (and residual-value guarantees if not included in minimum lease payments).
- Reported annual lease-related operating expenses for the most recent year.
- Deferred gains on sale-and-leaseback transactions that created operating leases.
- We use a fixed discount rate of 7% for all corporate entities we rate. Theoretically, the discount factor could be calculated as the weighted average of the implicit interest rates (that is, the rates charged by the lessors) in each of the company's operating lease arrangements. This is not practicable, however, given accounting disclosure limitations.
- The annual operating-lease-related expense, which we estimate using the average of the first projected annual payment disclosed at the end of the most recent year and the previous year.

174. Calculations (operating leases):

- Debt: We add to debt the present value of future lease payments, calculated using a 7% discount rate. Since minimum lease payments beyond the fifth year are regularly disclosed in aggregate as "thereafter," our methodology assumes that payments beyond the fifth year equal the payment amount in year five, and that the number of years in the "thereafter" period equals the "thereafter" amount divided by the fifth-year amount, rounded to the nearest year. This assumption is capped at a total payment profile of 30 years. IFRS allow companies to disclose amounts payable in years two through five as a single combined amount, instead of separate amounts for each year. In this case, we assume a flat annual payment amount in years two through five, based on the total minimum lease payment disclosed for these four years. We consider future lease payments to be net of sublease rental income only if the lease and sublease terms match and the holder of the sublease is sufficiently creditworthy (that is, has credit quality equivalent to 'BBB-' or higher).

- Income statement and cash flow measures: The lease-related expense is allocated to interest and depreciation expense. EBITDA is increased by adding back the interest and depreciation expense. EBIT is increased by adding back the interest expense. FFO and CFO are increased by adding back the depreciation expense. Gains or losses on sale-and-leaseback transactions are excluded from these measures.
- Interest expense: Interest expense is increased by the product of the 7% discount rate multiplied by the average net present value of the lease payments for the current and previous years.
- Capital expenditures: Our base calculation of capital expenditures, and therefore free operating cash flow (FOCF), excludes any implied capital expenditures relating to operating leases. For lease-intensive sectors, we may use a separate FOCF measure, which includes a capital-expenditure operating lease adjustment, to compare companies' lease and purchase decisions. For this separate FOCF measure, the capital expenditures figure is increased by an implied amount of capital expenditures relating to leases, calculated as the year-over-year change in lease debt, plus annual operating lease depreciation. This amount cannot be negative.
- Property, plant, and equipment: We add the amount of operating leases we reclassify as debt to property, plant, and equipment to approximate the depreciated asset cost.

175. Calculations (finance leases):

- Debt: To the extent that they are not already included in reported debt, we add to debt, finance lease obligations and any obligation associated with failed sale-and-leaseback transactions.
- Capital expenditures: Our base calculation of capital expenditures, and therefore FOCF, excludes any implied capital expenditures relating to finance leases. For lease-intensive sectors, we may use a separate FOCF measure, which includes a capital-expenditure finance lease adjustment, to compare companies' lease and purchase decisions. For this separate FOCF measure, capital expenditures are increased by the value of assets acquired via finance leases during the period.

12. Postretirement employee benefits and deferred compensation

176. We include underfunded defined-benefit obligations for retirees, including pensions and health care coverage (collectively, postretirement benefits or PRB) in our measure of debt. These obligations also include other forms of deferred compensation like retiree lump-sum payment schemes and long-service awards. We include these obligations in our measure of debt because they represent financial obligations that must be paid over time.

177. The adjustments we make relate solely to existing obligations, rather than to potential future obligations.

178. Unlike debt, the measurement of PRB obligations is inherently uncertain: The amount of benefits payable and the value of any assets earmarked to fund those obligations fluctuate over time.

179. To simplify the numerical analysis, we aggregate all retiree benefit plan assets and liabilities for pension, health, and other obligations, netting the positions of a company's plans in surplus against those that are in deficit.

180. We tax-effect our PRB adjustment amounts (that is, give credit for associated tax benefits), unless the related tax benefits have already been, or are unlikely to be, realized. We use the tax rates applicable to the company's plans or, if this is unavailable, the current corporate rate, even though the actual effect of tax charges or benefits in the future may be different. In a typical situation, the company has credible prospects of generating sufficient future taxable income to take advantage of tax deductions related to PRB and so reduce future tax payments.

181. We do not tax-effect the adjustment amounts if we consider a company's ability to generate profits uncertain. Moreover, in such cases, our main focus is the company's liquidity, rather than its capitalization or debt-coverage levels.

a) Capital structure

182. We adjust capitalization for PRB effects by adjusting both debt and equity, where applicable. Debt is increased by the company's tax-effected unfunded PRB obligation. In the instances where equity does not reflect the full extent of the underfunded deficit, equity is adjusted by the difference between the amount accrued on the corporate balance sheet and the amount of net over- or underfunded obligation (net surplus or deficit), net of tax. Debt is not adjusted downward for net surpluses, so net overfunding (surplus) leaves debt unchanged. Equity can be adjusted upward (if the net recognized asset is less than the pretax surplus) or downward. We do not split the debt adjustment between short and long term.

b) Cash flow

183. With PRB and deferred compensation plans, companies are effectively compensating their employees by issuing debt. Our cash flow view is that companies are constructively borrowing from the employees and paying the employees an amount equal to service costs. Additionally, because there is an interest element to the amount borrowed, our cash flow measures assume that imputed interest is paid as incurred. This approach takes a normalized view of cash flows: That is, regardless of when the pension plan is funded over the life of the plan, service costs and net interest costs are paid when incurred.

184. With that in mind, if a company is funding postretirement obligations at a level that is below its net expense (service cost and net interest cost), we interpret this as a form of borrowing that artificially bolsters reported CFO. Conversely, we try to identify catch-up contributions made to reduce unfunded obligations, which would artificially depress reported CFO. We view these contributions as akin to debt amortization, which represents a financing cash flow rather than an operating cash flow.

c) Income statement

185. For the purposes of arriving at income statement measures, we disaggregate the periodic benefit cost into its component parts, allocate those amounts to operating and financing components, and eliminate components we believe are not indicative of the current year's activity. The period's current service cost--reflecting the present value of future benefits employees earned for services rendered during the period--is the sole item we keep as part of operating expenses. We view the interest expense as a finance charge and reclassify it as such if reported differently, such as within operating expenses.

186. Under U.S. GAAP, the expected return on plan assets represents management's subjective, long-range expectation about the performance of the investment portfolio. This concept has been abandoned under IFRS, which under revised

accounting standards, now calculates a net interest figure by multiplying the deficit (or surplus) on the PRB by the discount rate. For the purposes of global comparability, we make adjustments to the reported data of companies still incorporating an expected return element into their interest calculations, such as those reporting under U.S. GAAP, to mimic the IFRS method of calculating net interest. This measure of PRB interest, if a net expense, is added to reported interest. No adjustment is made if net interest is a net income item.

Adjustment procedures

187. Data requirements (for adjustments to income and cash flow items):

- Service cost;
- Interest cost;
- Expected return on pension plan assets, if applicable;
- Actuarial gains or losses (amortization or immediate recognition in earnings);
- Prior service costs (amount included in earnings);
- Other amounts included in earnings (such as special benefits, settlements, and curtailments of benefits);
- Total benefit costs; and
- The sum of employer contributions and direct payments to employees.

188. Data requirements (for adjustments to balance-sheet items):

- PRB-related assets on the balance sheet, including intangible assets, prepaid or noncurrent assets, or any other assets;
- Reported liabilities attributed to PRB, including current and noncurrent liabilities;
- Deferred tax assets related to PRB (or the tax rate applicable to related costs);
- Fair value of plan assets; and
- Total plan liabilities.

Note: Relevant pension and other PRB amounts are combined for all plans.

189. Calculations (income statement and cash flows):

- Operating income: Add to EBIT and EBITDA the total amount of PRB costs charged to operating income, less the current service cost.
- Interest: PRB interest is the net interest cost as reported by companies under IFRS, or as we estimate for companies reporting under U.S. GAAP and other companies using the expected-return approach. If PRB interest is a cost, we include it in adjusted interest expense (we do not reduce interest expense if PRB interest is an income item). This PRB interest is added to reported interest when the net benefit costs are included in operating income. If reported interest already includes an interest component for PRB we adjust it, if necessary, to ensure it reflects the amount of PRB interest.
- Tax expense: We add to, or subtract from, reported tax expenses any tax charge or benefit that results if a company makes additional contributions to postretirement plans or falls short of planned contributions for the current year.
- FFO: FFO equals EBITDA minus net interest expense, minus current tax, with our analytical adjustments applying to each of the three components. EBITDA is adjusted for PRB as described in the first bullet point of this paragraph, while the adjusted net interest expense includes the PRB net interest cost or credit. The current tax expense is adjusted to reflect any tax benefit or charge that the company has received through making excess or insufficient contributions. The net effect of this is that FFO is reduced by the sum of current service costs and net PRB interest, adjusting for tax effects.

- CFO: The adjustment to CFO starts with a calculation of excess contributions or PRB borrowing: Total employer cash contributions (including direct payments to retirees), minus current service costs, minus PRB interest yields the excess contribution if positive, or PRB borrowing if negative. The excess contribution or PRB borrowing is reduced by taxes at the rate applicable to PRB costs (that is, the figure multiplied by 1 minus the tax rate) to create the adjustment amount to CFO. The excess contribution or PRB borrowing is added to, or subtracted from, CFO.

190. Calculations (balance sheet):

- Debt: The net balance sheet asset or liability position (funded status) is calculated as the balance-sheet PRB assets minus PRB liabilities. For the adjustment to debt, if the net pension and postretirement funded status is positive, debt is not adjusted. If the net pension and postretirement funded status is negative, this amount is reduced by the expected tax shield, that is, the amount is multiplied by 1 minus the tax rate. The resulting net amount is added to debt.
- In some jurisdictions, the tax benefit is realized in advance of funding the deficit or paying benefits, for example, when the liability is accrued for tax purposes. The expected tax shield used in our calculation only takes into account amounts that have not yet been received. The adjustment to equity also considers existing balance-sheet amounts.
- Equity: We add to, or subtract from, equity the tax-effected difference (that is, after multiplying that figure by 1 minus the tax rate) between the deficit or surplus on the PRB plan and the reported net plan assets and liabilities.

13. Scope of consolidation

191. When analyzing the creditworthiness of a group, a first critical step is to determine the manner in which a company reports the results of its subsidiaries and affiliates (including their operations, cash flows, assets, and liabilities) in its financial statements. There are several accounting methods to reflect a company's relationship with another company: full consolidation, proportionate consolidation, equity-method consolidation, and deconsolidation (that is, accounted for as an investment).

192. Full consolidation of a subsidiary entails including 100% of each line item of its income, cash flows, assets, and liabilities in the group's financial statements. When a parent owns less than 100% of a subsidiary, the non-controlling-interest holder's share is shown on a separate line in the consolidated income statement and balance sheet.

193. Proportionate consolidation of an affiliate is when all line items of a parent's financial statements include its pro rata share of the affiliate's income, cash flows, assets, and liabilities. This method of consolidation is not common in accounting, but we use it from time to time if we believe that proportionate consolidation best reflects a company's business and financial ties with subsidiaries and affiliates.

194. The equity method of consolidation involves showing the parent's share of profits (or losses) on one line in the income statement, and the parent's investment (initial price paid plus the post-acquisition share of changes in the affiliate's net assets) on the balance sheet. Only cash dividends are reflected in the parent's cash flow statement.

195. Reporting as a nonconsolidated (or deconsolidated) investment means the parent company shows the value of the investment on its balance sheet, typically measured at cost or fair value. The parent does not include any of the income of that affiliate in its results, but reports cash dividends received in the cash flow statement.

196. Although most often the scope of consolidation we employ when analyzing a company is the same as that in the company's financial statements, we may use any consolidation method that in our opinion best reflects a company's business and financial ties with its subsidiaries and affiliates. The analytical adjustments would therefore serve to convert the reported figures to those consistent with our chosen method.

197. No single factor determines our analytical view of a company's relationship with a particular business venture. Rather, the decision will reflect an assessment of factors that, taken together, will lead to a particular characterization. These factors include:

- Strategic importance--integrated lines of business or critical supplier;
- Percentage of ownership (current and prospective);
- Management control;
- Shared name;
- Domicile in the same country;
- Common sources of capital and lending relationships;
- Financial capacity for providing support;
- Significance of the amount of investment;
- Investment relative to the amount of debt at the affiliate or project;
- Position of the other owners (whether strategic or financial investment) and their financial capacity;
- Management's stated stance toward the affiliate or project;
- Whether the creditors of the subsidiary or affiliate have recourse to the parent;
- Shared collective bargaining agreements;
- The bankruptcy-law regimes applicable to the parent and subsidiary;
- Track record of the parent company in similar circumstances; and
- The nature of potential risks.

Adjustment procedures

198. Because a company can use various consolidation methods, there is no standard adjustment procedure. We adjust the reported figures to reflect our quantitative view of the group.

14. Securitization and factoring

199. Securitization can be an important financing vehicle for many companies, potentially enhancing liquidity and enabling them to diversify their funding sources. An important factor is whether the assets and liabilities of a securitization are shown on a company's balance sheet, or deconsolidated and reported as an off-balance-sheet transaction.

200. We may reconsolidate a securitization that a company reports as off-balance-sheet financing. This is because securitizations do not ordinarily transform the risks or the underlying economic reality of the business activity, nor do they necessarily provide equity relief, which allows the company to retain less equity or incur more debt than would otherwise be the case, without affecting its credit quality.

201. If a securitization accomplishes true transfer of risk (contractual, legal, and reputation risk), as is the case with securitization of a tax asset, we regard the transaction as an asset sale and make no adjustments, subject to the considerations in paragraphs 202-206.

202. More commonly, a company retains risks related to the assets transferred under the securitization transaction. We

regard such transactions as being akin to secured financing and bring them back onto the balance sheet if the company has treated them as off-balance-sheet items. The analysis also indicates whether the securitization creates a disadvantage for a company's unsecured creditors that would affect our rating on unsecured debt issues.

203. For example, in our analysis, we treat as on-balance-sheet items, securitization of assets (such as trade receivables) that are regenerated in the ordinary course of business and financed on an ongoing basis. This is because the assets and trading relationships these assets represent are an integral part of a company's operations. Even if a transaction legally transferred risks related to a pool of assets and the company has no obligation to support failing securitizations, this does not mean the company would receive equity relief or that we would not reconsolidate the securitization in our analysis. If a company has a recurring need to finance similar assets, we do not presume it will have permanent access to the securitization market. The company may have to meet future funding needs by other means, and therefore have the requisite equity (and the equivalent level of borrowings) to do so.

204. We treat factoring (or invoice discounting) of trade receivables in a similar way, by including the trade receivable asset and the associated funding liability in the company's balance sheet.

205. Other key considerations for the adjustment of securitizations include:

- The riskiness of the securitized assets. If, as is often the case, a company securitizes its highest-quality or most liquid and therefore low-risk assets, this would limit the extent of any meaningful equity relief, and may create subordination of unsecured creditors, which if significant enough could have an impact on our rating on unsecured debt.
- First-loss exposure. A company may retain liability for a defined portion of loss from a securitization (known as "first-loss exposure"), thereby providing structural credit protection for the securitized asset, which would lower funding costs. The first-loss layer may absorb much of the risk of the securitized asset, and the total gain or loss from the securitization will vary depending on the performance of the assets. Often, only the risk of loss that exceeds the first-loss exposure is transferred to third-party investors.
- Moral recourse. This refers to the likelihood that a company will support a securitization although not legally obliged to do so. Our assessment of moral recourse reflects our view of how a company could behave if losses on the securitization reached catastrophic levels. There is evidence to suggest that companies often tend to bail out troubled securitization transactions (for example, by repurchasing problematic assets or replacing them with other assets) to preserve access to this funding source and, more broadly, to preserve their good name in the capital markets. Moral recourse is magnified when securitizations make up a significant portion of a company's total financing, or when a company remains linked to the securitized assets through the use of a shared corporate name or by continuing in the role of servicer or operator. If we regard the likelihood of moral recourse as significant, we regard the securitized asset and liability as part of the company's balance sheet.

206. The adjustments to a company's financial statements also depend on the extent of risk transfer resulting from a securitization:

- If a company retains most of the risk, our cash flow/leverage ratio calculations include the securitized debt, regardless of whether the securitized debt was reported as on-balance-sheet debt or accounted for as an off-balance-sheet transaction.
- If the company retains none of the risk, the securitized assets are not regenerated in the ordinary course of business, and there are no contingent or indirect liabilities resulting from the transaction, we view the securitization as

equivalent to an asset sale and exclude it from our analysis of the company. This means that if a company has consolidated such a transaction, we use adjustments to remove the securitization assets, debt, earnings, and cash flows from the reported consolidated results in our analysis. We also adjust shareholders' equity, including for the effect of deferred taxes and imputed (or assumed) interest.

207. Several factors limit our ability to make full adjustments for securitizations. When a company reports a securitization as an asset sale in its financial statements, this may create an upfront gain or loss on the sale. When we reconsolidate such a securitization, it is appropriate to reverse such gains because of the uncertainty about whether they will be realized and because they represent nonrecurring income. Likewise, we reverse any loss on the sale that reflects the discount on the sale, to prevent double counting the interest component of the transactions.

208. To calculate the imputed interest, we generally estimate an interest rate because of insufficient information. That rate approximates the interest rate on similar transactions.

209. It is impractical to fully recast the financial statements to consolidate off-balance-sheet securitizations because companies are not required to include pro forma schedules including the securitization transaction in their published accounts.

210. Under U.S. GAAP and IFRS, companies report cash inflows or outflows related to working-capital assets or liabilities, or finance receivables, as operating items on the statement of cash flows. Consequently, securitizations of assets such as receivables affect CFO, and the effect may be particularly significant in reporting periods when the securitizations are initiated or mature.

211. The reporting convention varies with the balance-sheet classification. If a company consolidates a securitization, the related borrowings are treated as a financing activity. If the securitization is off the balance sheet, the effect is akin to accelerated liquidation of the associated assets. There is no separate record of the incurrence of debt, either as an operating liability or a financing source of cash.

212. When our approach is to consolidate a securitization (or, in rare situations, to deconsolidate a securitization), we adjust the cash flow statement to smooth out the variations in CFO that can result from the treatment of a securitization as a sale, which can distort the pattern of recurring cash flow.

Adjustment procedures

213. Data requirements:

- The period-end amount and average outstanding amount of trade receivables sold or securitized that are not on the balance sheet and require adjustments according to our criteria.

214. Calculations:

- Debt and receivables: Add the amount of period-end trade receivables sold or securitized (that is, the uncollected receivables as of the balance-sheet date) to reported debt and receivables.
- Interest expense: Add to interest expense the amount of imputed interest, calculated using the average trade receivables sold over a two-year period (if the data are available) or the trade receivables sold as of the period-end date, at an appropriate benchmark interest rate.
- CFO: Deduct from CFO the proceeds from the securitization if the transaction results in large cash flow movements,

such as on the creation of a securitization or subsequent changes in amounts securitized. Rolling over an existing securitization requires no cash flow adjustment.

15. Seller-provided financing

215. Companies acquiring other companies sometimes finance a portion of the purchase price (or consideration), via seller-provided financing and/or entering into contingent consideration arrangements (that is, "earn outs"). We often view these transactions as a form of financing and therefore we make analytical adjustments to reflect this view. The accounting approach under U.S. GAAP is materially consistent with that under IFRS.

216. The most straightforward form of seller-provided financing is a loan reported at amortized cost plus interest. We include the reported debt amount and interest expense in our respective measures to the extent that they are not already reported as such. No adjustment is necessary on the statement of cash flows, apart from any interest reported under IFRS outside of CFO.

217. The reporting of contingent consideration is more convoluted given the complexity and variability of the instruments. Contingent consideration can take many forms: It can be paid in cash or shares, it can be contingently payable by the acquirer or prepaid and contingently returnable to the acquirer, or it can be contingent upon the recipient's continued employment with the acquirer after the acquisition. The nature and terms of an arrangement dictate the accounting for the arrangement and our analytical treatment.

218. Contingent consideration payable in shares is generally reported within equity and is not remeasured in reporting periods subsequent to the transaction. We do not add to debt an amount for the anticipated settlement of these transactions because we consider them to be prospective equity issuance.

219. Contingent consideration that is prepaid and contingently returnable to the acquiring entity results in an asset on the acquirer's balance sheet that is marked to market in each accounting period until settled. We make no adjustments for these arrangements because they are effectively receivables with no potential future cash outlay. However, we would adjust CFO if the acquirer reported any returned consideration within CFO.

220. Contingent arrangements that require continued employment are technically not part of the consideration paid for the acquisition under U.S. GAAP and IFRS. Rather, such transactions represent remuneration for services after the acquisition. As such, the company does not record the transaction as a liability or expense until the services are performed. We also view such arrangements as payment for services and generally make no analytical adjustments. The recognized expense is a component of our EBITDA and FFO, and its ultimate payment should reduce CFO. Additionally, we do not adjust the reported debt figure unless the original term of the liability was greater than 12 months.

221. Our primary focus is on contingent consideration that is payable in cash, or contracts to be settled in shares that do not qualify as equity. The most common example is a contract to be settled with a variable number of shares. Companies typically record such arrangements, initially, as a liability at fair value and subsequently mark them to market at the end of each accounting period via charges or credits to income until settled. We add to debt the reported value of the liability-classified contingent consideration on each reporting date, understanding that it is not at amortized cost.

222. Consistent with our view of cash flows, described in the next paragraph, we exclude the charges or credits to income from our measurement of EBITDA and FFO, on the basis that this recognition of measurement uncertainty in the income statement is not a core operating cost, but an additional cost of the acquisition. We generally do not attempt to make adjustments to interest expense; such adjustments are usually impractical because interest on the contingent consideration is typically not disclosed.

223. When a company ultimately pays the contingent consideration to the seller, it may report the cash outflow in several ways in the statement of cash flows. We regard these outflows as investing cash flows because they represent cash paid for the purchase of a business. Any cash settlements reported in other ways (for example, as operating or financing cash flows) will be adjusted to reflect this view.

Adjustment procedures

224. Data requirements:

- The carrying value of seller-financed debt or liability-classified contingent consideration on the balance-sheet date.
- Charges or credits included in reported EBITDA.
- Cash paid for or received from the settlement of contingent consideration reported either in cash flows from operating activities or cash flows from financing activities.

225. Calculations:

- Debt: Add to debt, to the extent not already reported as such, the carrying amount of seller-financed debt at amortized cost, as well as any liability-classified contingent consideration reported at fair value.
- EBITDA: If charges or credits from the change in fair value of contingent consideration are included in reported EBITDA, add them back to or subtract them from EBITDA.
- CFO: If cash settlements are reported in CFO, remove the outflow because we consider it an investing activity (acquisition of businesses).

16. Share-based compensation expenses

226. Most major accounting regimes require companies to report the fair value of equity-based grants (such as stock options and restricted share awards) as an expense in the income statement. This amount is generally expensed over the benefiting period, that is, the period over which the company estimates the employee is providing services in exchange for the award.

227. Our cash-flow measures, such as CFO, are not affected by share-based grants payable in shares, given their inherent noncash nature. Additionally, we add back stock-based compensation that is payable in shares to EBITDA and FFO. Our key cash flow/leverage ratios--FFO to debt and debt to EBITDA--therefore exclude stock option expense related to arrangements payable in shares.

228. Certain other share-based arrangements, unlike options or restricted share awards, are payable solely in cash. Examples are stock appreciation rights that are required to be settled in cash, which represent a future call on a company's cash flow. Because they are payable in cash, we do not add back the expense related to these arrangements to EBITDA and FFO. We treat obligations under these arrangements as debt.

Adjustment procedures

229. Data requirements:

- Total share-based compensation expense reported in the period that is payable in shares.
- In jurisdictions that do not require the expensing of such compensation, an estimate of the expense.

230. Calculations:

- EBITDA: If a company has accounted for noncash stock compensation costs as an expense, we add that figure back to EBITDA.
- Operating income, before and after D&A, and EBIT: In jurisdictions that do not require companies to report share-based compensation as expenses, we estimate an expense amount and deduct it from these measures.
- Debt: Add to debt share-based arrangements payable solely in cash.

17. Surplus cash

231. We apply a standard method of calculating surplus cash, which is the amount of cash and liquid investments that is subtracted from gross debt to calculate debt.

232. Standard & Poor's payback ratios are intended to capture the degree to which a company has leveraged its risk assets. Highly liquid financial assets are often low risk. Moreover, we consider that, in addition to cash flow generation, surplus cash is available to repay debt, providing additional flexibility that enhances a company's credit quality. Therefore, it is appropriate to evaluate debt net of surplus cash.

233. Our standard methodology for calculating surplus cash allows the netting of available cash and liquid investments if in our judgment they are highly liquid, and if they are accessible; that is, the cash and liquid investments are truly surplus and therefore could be used to repay debt immediately.

234. We analyze the specifics of a company's cash holdings to evaluate how much of its cash is immediately accessible to reduce debt. To calculate how much cash can be netted off from debt, and unless we get enough information or identify analytical reasons supporting either a lower or higher haircut, we will deduct 25% from the available cash (A), identified as "cash and liquid investments" in "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published on Nov. 19, 2013, to reflect cash that is inaccessible. If we apply the default 25% haircut, adjusted cash (B) available for netting from gross debt would be A x 0.75 = B.

235. We identify cash that might be inaccessible due, among other reasons, to:

- Being held in a nonconvertible currency to the currency of a company's borrowings;
- Distribution restrictions (for example, covenants or cash held in escrow);
- Cash trapped at subsidiaries;
- Tax effects on the repatriation of cash;
- Period-end timing differences unrelated to working capital; or
- Being held in a country whose country risk we assess as high (country risk score of 5) or very high (country risk score of 6), and is in a different currency from the currency of the company's borrowings.

236. If available information indicates greater or lesser accessibility to cash and liquid investments, the haircut would be raised or lowered. For example, the haircut would increase if a company holds a large proportion of cash abroad in a

nonconvertible currency, or if the marginal tax payable on repatriation would exceed 25%. On the other hand, the haircut percentage would be lowered if, for example, detailed analysis showed that the amount of cash and liquid investments accessible on short notice would be higher than our standard assumption, or if any tax payable on repatriation of the cash and liquid investments would be at a rate of less than 25% and we believed that no other factors make the cash and liquid investments inaccessible.

237. If we forecast that a company will generate negative cash flow available for debt repayment, our cash flow/leverage criteria places greater reliance on the current year and the first and second forecast years (see paragraph 117 in "Corporate Methodology," published on Nov. 19, 2013). Forecast negative cash flows could stem from operating activities as well as share buybacks, dividends, or acquisitions, if we forecast these uses of cash based on the company's track record.

238. We will generally not deduct surplus cash from debt if a company is (1) owned by a financial sponsor as defined in Section H.2 of "Corporate Methodology," published on Nov. 19, 2013, or (2) has a business risk profile assessment of "weak" or "vulnerable." However, we deduct surplus cash from debt even if a company meets either of these conditions, as long as:

- We believe that the company has surplus cash identified to retire maturing debt or other debt-like obligations; and
- We believe--typically from the company's track record, market conditions, or financial policy--that management will use the cash to pay off maturing debt or debt-like obligations.

18. Workers' compensation and self-insurance

239. Workers' compensation schemes provide compensation for employees injured in the course of employment. Although schemes differ across jurisdictions, provisions may be made for payments to employees in lieu of wages, compensation for economic losses (past and future), reimbursement for, or payment of, medical and similar expenses, general damages, and benefits payable to the dependents of workers killed during employment.

240. Workers' compensation coverage may be provided through insurance companies, and therefore is not a financial concern for the company. But, in certain instances and/or industries, employers assume direct responsibility for payments such as medical treatment or lost wages.

241. In these cases, under U.S. GAAP or IFRS, the company reports incurred liabilities on the balance sheet as "other liabilities," using an actuarially determined present value of known and estimated claims. Accordingly, these obligations represent a call on future cash flow, distinguishing them from many other less-certain contingencies. They are analogous to postretirement obligations, which we also add to debt.

242. Treating the workers' compensation liability as debt affects many line items on the financial statements. Ideally, if there is sufficient information in the statements, we would make full adjustments, using the same approach as for postretirement employee benefits (see paragraphs 176-190). In practice, the data is not available, so we reclassify these obligations, adjusted for tax, as debt. We may also treat similar self-insurance-type liabilities as debt.

Adjustment procedures

243. Data requirements:

- Net amount reported as a liability for workers' compensation obligations and self-insurance claims.

244. Calculations:

- Debt: Add to debt, the amount recognized for workers' compensation obligations (net of tax) and the net amount recognized for self-insurance claims (net of tax).

F. Index Of Key Ratios

245. Core debt-payback ratios:

- Funds from operations (FFO)/debt
- Debt/EBITDA

246. Supplemental debt-payback and debt-service ratios:

- Cash flow from operations (CFO)/debt
- Free operating cash flow (FOCF)/debt
- Discretionary cash flow (DCF)/debt
- (FFO + interest)/cash interest (FFO cash interest cover)
- EBITDA/interest

247. Profitability ratios:

- EBIT/revenues (EBIT margin)
- EBITDA/revenues (EBITDA margin)
- EBIT/average beginning-of-year and end-of-year capital (return on capital)

VI. GLOSSARY

248. ***Capital:*** Debt plus noncurrent deferred taxes plus equity (plus or minus all applicable adjustments).

249. ***Capital expenditures:*** Funds spent to acquire or develop tangible and certain intangible assets (plus or minus all applicable adjustments).

250. ***Cash interest:*** For the purposes of calculating the FFO cash-interest-cover ratio, "cash interest" includes only cash interest payments on gross financial debt (including bank loans, debt capital market instruments, finance leases, and capitalized interest). Cash interest does not include any Standard & Poor's-adjusted interest on debt-like obligations, such as postretirement benefit obligations or operating leases.

251. ***CFO (cash flow from operations):*** CFO is also referred to as operating cash flow. This measure reflects cash flows from operating activities (as opposed to investing and financing activities), including all interest received and paid, dividends received, and taxes paid in the period (plus or minus all applicable adjustments). For companies that do not use U.S. GAAP, we reclassify as CFO any dividends received, or interest paid or received, that a company reports as investing or financing cash flows.

252. ***Current tax expense:*** This is the amount of income taxes payable on taxable profit, or income tax recoverable from tax losses, in an accounting period (plus or minus all applicable adjustments). Current tax expense is to be distinguished from deferred tax expense.

253. ***DCF (discretionary cash flow):*** FOCF minus cash dividends paid on common stock and preferred stock (plus or minus all applicable adjustments).

254. ***Debt:*** Gross financial debt (including items such as bank loans, debt capital market instruments, and finance leases) minus surplus cash (plus or minus all applicable adjustments).

255. ***Dividends:*** Dividends paid to common and preferred shareholders and to minority interest shareholders of consolidated subsidiaries (plus or minus all applicable adjustments).

256. ***EBIT:*** A traditional view of profit that factors in capital intensity, but also includes interest income, the company's share of equity earnings of associates and joint ventures, and other recurring, nonoperating items (plus or minus all applicable adjustments).

257. ***EBITDA:*** A company's revenue minus operating expenses, plus depreciation and amortization expenses, including impairments on noncurrent assets and impairment reversals (plus or minus all applicable adjustments). Dividends (cash) received from affiliates, associates, and joint ventures accounted for under the equity method are added, while the company's share of profits and losses from these affiliates is excluded.

258. ***Equity:*** Common equity and equity hybrids and minority interests (plus or minus all applicable adjustments).

259. ***FFO (funds from operations):*** EBITDA, minus net interest expense minus current tax expense (plus or minus all applicable adjustments).

260. ***FOCF (free operating cash flow):*** CFO minus capital expenditures (plus or minus all applicable adjustments).

261. ***Interest:*** This is the reported interest expense figure, including noncash interest on conventional debt instruments (such as payment-in-kind, zero-coupon, and inflation-linked debt), minus any interest income derived from assets structurally linked to a debt instrument (plus or minus all applicable adjustments).

262. ***Net interest expense:*** This is the reported interest expense figure, including noncash interest on conventional debt instruments (such as payment-in-kind, zero-coupon, and inflation-linked debt), minus the sum of interest income and dividend income (plus or minus all applicable adjustments).

263. ***Revenues:*** Total sales and other revenues we consider to be operating (plus or minus all applicable adjustments).

VII. APPENDIX

264. This criteria article supersedes:

- "2008 Corporate Criteria: Ratios And Adjustments," published on April 15, 2008;
- "Methodology And Assumptions: Standard & Poor's Revises Key Ratios Used in Global Corporate Ratings Analysis," published on Dec. 28, 2011;
- "Recognizing The Settlement Obligation For Foreign-Currency Hedges Of Debt Principal," published on April 15, 2010;
- "Methodology And Assumptions: Recognizing The Sustainable Cash Cost Of Inflation-Linked Debt For Corporates," published on Feb. 10, 2009;
- "Calculating Adjusted Debt And Interest For Corporate Issuers," published on June 2, 2008;
- "Standard & Poor's Approach To Analyzing Employers' Participation In U.S. Multi-Employer Pension Plans," published on May 30, 2006;
- "Analytical Approach To Postretirement Liabilities of Japanese Companies," published on March 31, 2003; and

- "Camouflaged Share Repurchases: The Rating Implications Of Total-Return Swaps And Similar Equity Derivatives," published on Dec. 7, 2000.

265. This criteria article partly supersedes the section Accounting And Financial Reporting in "2008 Corporate Criteria: Analytical Methodology," published on April 15, 2008.

Frequently Asked Questions

A. Surplus cash

Is the 25% deduction from cash and liquid investments, as described in paragraph 234, the standard amount Standard & Poor's uses to arrive at surplus cash and calculate adjusted debt?

No. The 25% deduction from cash and liquid investments should only be used if we do not have information that would enable the calculation of a more precise amount. If available information indicates greater--or lesser--accessibility to cash and liquid investments than what is assumed by the 25% deduction, we'd lower or raise the amount of the deduction. The deduction should only represent cash at the balance sheet date that is inaccessible to pay interest or repay debt in case of need. Often, we would expect the deduction to be less than 25%.

Can it be appropriate to have a different deduction from cash and liquid investments in arriving at surplus cash each year?

Yes, a different deduction from cash and liquid investments each year is often appropriate. We deduct from cash and liquid investments the amount of cash and liquid investments we believe is, or will be, inaccessible. That amount may not remain constant so a different percentage in each year can better reflect reality.

When developing the deduction from cash and liquid investments to arrive at surplus cash, do you exclude a minimum amount of cash necessary to run the business from the deduction? Could such a minimum amount of cash qualify as "cash trapped at subsidiaries," as noted in paragraph 235?

Generally no. When calculating surplus cash, cash and liquid investments should not be reduced by the amount of expected working capital investment needs. This is because this would disadvantage companies that fund working capital from cash rather than by drawing down on bank lines. In addition, as working capital investment should be "self-extinguishing" or "self-liquidating"--as stock and debt (i.e. inventory and receivables) are converted into cash--it is not appropriate to increase debt for working capital investment needs by reducing cash and liquid investments in the calculation of surplus cash. However, to the extent that we believe that some of the company's working capital investment won't be "self-extinguishing"--due to factors such as stock write-offs, stock discounting, or bad debts--this would be captured in weaker profits in the base-case forecast, which would reduce cash flows and future cash balances. In addition, such working capital investment needs would not qualify as "cash trapped at subsidiaries." An exception to this approach could be where a company has indicated to us an operational cash requirement such that 'cash in the tills' is not practically accessible because it is needed to operate their business (examples include a supermarket who needs cash in tills, or a casino who needs to retain cash in cages). In such cases, we treat this cash need as part of the 'cash trapped at subsidiaries' condition (see paragraph 235).

Do you consider future events (e.g., large expected cash outflows related to capital expenditures, acquisitions, share buybacks and dividends, or lower forecasted earnings) in developing the haircut to gross cash and liquid investments in a particular period?

No. The haircut to gross cash and liquid investments is only for matters of inaccessibility, not future events or needs.

The expected cash outflow or reduced earnings should be included in the base-case forecasts. This will reduce forecast cash flows and period-end cash balances.

Should the haircut applied to liquid investments consider the taxes that would be incurred upon the sale of liquid investments?

Yes. The same principle we apply when tax-effecting cash held overseas should apply here. If the issuer needs to sell liquid investments to generate cash to pay interest or repay debt, the cash that would be received and would be available to pay interest and repay debt would be the net amount of cash after any taxes payable.

Paragraph 235 states that "We identify cash that might be inaccessible due, among other reasons, to…distribution restrictions (for example, covenants or cash held in escrow…)". Are there cases where Standard & Poor's could net off cash that is subject to distribution restrictions from gross debt to calculate debt? If so, do the qualitative preclusions to deducting surplus cash noted in paragraph 238 apply?

Yes, there can be situations where we net off cash that is subject to distribution restrictions from gross debt as part of the surplus cash adjustment--if the cash is restricted for the benefit of creditors with obligations that we include in debt. In these cases, the qualitative restrictions on giving surplus cash credit do not apply, just as they do not apply to netting off other committed assets such as pension assets. For example, if the purpose of the cash distribution restriction is to retain the cash for the benefit of counterparties to debt or debt-like obligations that are otherwise included in our adjusted debt metric, such restricted cash could be netted off gross debt. For example, cash held in escrow for the benefit of debtholders would be fully netted off from debt if the debt is included in Standard & Poor's debt calculation. Additionally, if the exclusion of restricted cash from cash and liquid investments in the calculation of surplus cash would run counter to one of our other analytical adjustments, the restricted cash could be netted off gross debt. An example of this is a cash-collateralized letter of credit facility whereby an issuer overfunds a term loan and places the excess funds in escrow as a back stop for letters of credit or performance guarantees. As long as we believe that the company will not have to make payments under the guarantee, such cash would be eligible for netting against gross debt. This is because, as paragraphs 99 and 100 state, "We do not regard performance guarantees as debt if a company is likely to maintain sufficient work or product quality to avoid making large payments under those guarantees. A company's past record of payments under performance guarantees could indicate the likelihood of future payments under such guarantees. Only if this payment history suggests a high likelihood of future payments would we estimate a potential liability and add that amount to debt."

If an issuer that Standard & Poor's classifies as volatile or highly volatile under the cash flow/leverage criteria has a large amount of surplus cash on hand during a favorable part of the industry cycle, but based on historical evidence you expect it will use most of that cash to meet operating needs during periods of stress, do you take this into account in the surplus cash analysis?

No. When calculating surplus cash, we would only haircut cash and liquid investments by the amount of any of the cash and liquid investments that are inaccessible. Any expected future uses of cash can be captured in the base-case forecast. If an issuer is assessed under the cash flow/leverage criteria to be volatile or highly volatile, then the cash flow/leverage assessment could be modified by one or two categories weaker (as per paragraph 124, section 5, of "Corporate Methodology," published Nov. 19, 2013).

B. Non-operating activities and non-recurring charges

What types of events constitute "transformative events" for the purpose of adjusting for non-recurring items? Is this the same threshold used in the cash/flow leverage criteria, and if so why is there a need to adjust if the weighted average is going to exclude history?

A transformative event is any event that could cause a material change in a company's financial profile. Examples of such changes are the divestment of part of the business or a fundamental change in operating strategy. The idea of a transformative event in these criteria is a similar concept to that contained in paragraph 112 of "Corporate Methodology." When transformative events have occurred and there is sufficient disclosure such that pro forma historical financials are representative of the ongoing entity, historical periods can be used in the cash flow leverage weighted average. Conversely, if the transformative event so alters the business or contorts the historical financials--such that analytical adjustments to historical financials cannot be reasonably employed to in effect pro forma the historical results to be representative of the ongoing entity--then adjustments will not be attempted. Instead, our cash flow leverage analysis will rely on the forecasted periods as described in paragraph 112 of "Corporate Methodology."

Do you adjust for certain accounting anomalies on a regular basis? Do these distortions for "measurement effects" or "accounting distortions," which can lead to misleading figures in the annual financial statements, qualify for adjustment under the non-recurring criteria despite not meeting the "transformative" threshold?

While such distortions are not transformative events per se, we do make adjustments for accounting distortions in certain circumstances for a similar reason: that is to arrive at more meaningful ratios (see paragraphs 140-167). The "nonoperating activities and nonrecurring items" section of the ratio and adjustments criteria gives examples of measurement effects and accounting distortions that we exclude from our financial measures, such as goodwill impairments or unrealized mark-to-market gains or losses on derivatives where a company has not achieved the requirements of technical hedge accounting, even though an effective economic hedge may exist. Other examples of measurement effects and accounting distortions that we exclude from our financial measures include:

- A change in the measurement of a material litigation provision that leads to very significant gains or losses in the year; and
- Fair valuation gains or losses on investment properties under IFRS.

C. Adjusted debt principle

The adjusted debt principle mentions that "to the extent that a company defers payment beyond the term customary for its supply chain, we may add that amount to debt." Under what circumstances would you apply this and how would it be calculated? And how does Standard & Poor's treat reverse factoring arrangements?

If we believe that an issuer's trade payable days are well beyond the range of what would be deemed normal trade terms for the industry, and the improvement to cash flow/leverage measures that results from the stretch in trade payables is deemed to be material, then we'd make an adjustment. In the case of reverse factoring--which we define as financing initiated by a company in order to help its suppliers finance their receivables--we may make a debt adjustment for the customer, if we believe that the trade payable days are well beyond the range of what would be deemed normal trade terms for the industry (see above). However, we would not make an adjustment to debt for the supplier if the supplier has no contractual commitment to meet the customer's obligations and we are confident there is no moral recourse or reputational risk to the supplier as part of the reverse factoring program.

Do structured settlements (e.g., tax settlements and tobacco settlements) qualify as debt under the adjusted debt principle?

Yes. The adjusted debt principle says that we add to debt "incurred liabilities that provide no future offsetting operating benefit." Structured settlements of dispute, whether with commercial or governmental entities, fit this principle and are added to debt (on a discounted basis if feasible).

Under the adjusted debt principle, do you treat a redeemable minority interest as debt?

Yes, but only when the redemption is outside of the control of the issuer (i.e., the minority interest holder has a put option on the subsidiary's shares as opposed to the issuer having a call option to repurchase the shares) and we fully consolidate the subsidiary in our analysis. The liability would be added to our adjusted debt figure based on the adjusted debt principle (see paragraph 21) since the subsidiary is fully consolidated into the parent's accounts and, therefore, the benefits of ownership are accruing to the issuer.

D. Litigation

How does Standard & Poor's capture the risk associated with a large legal settlement, if not quantitatively captured as part of an adjustment to debt?

As stated in paragraphs 191 and 192 of "Corporate Methodology," we consider as part of our Comparable Ratings Analysis factors that may not be already or fully captured elsewhere in our analysis, such as this type of risk. Such factors will generally reflect less frequently observed credit characteristics, may be unique, or may reflect unpredictability or uncertain risk attributes, both positive and negative. In particular, we could assign a negative assessment for Comparable Ratings Analysis, depending on how well (or not) a company identifies, manages, and reserves for contingent risk exposures that can arise if guarantees are called, derivative contract break clauses are activated, or substantial lawsuits are lost.

Related Criteria And Research

- Corporate Methodology, Nov. 19, 2013
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Nov. 19, 2013
- Methodology And Assumptions: Assigning Equity Content To Corporate Entity And North American Insurance Holding Company Hybrid Capital Instruments, April 1, 2013
- Criteria Clarification On Hybrid Capital Step-Ups, Call Options, And Replacement Provisions, Oct. 22, 2012
- Principles Of Credit Ratings, Feb. 16, 2011
- Methodology: Hybrid Capital Issue Features: Update On Dividend Stoppers, Look-Backs, And Pushers, Feb. 10, 2010
- Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008

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

Southwestern Public Service Company

Subsidiary of Xcel Energy Inc.

Rating Type	Rating	Outlook	Last Rating Action
Long-Term IDR	BBB	Stable	Affirmed 29 March 2018
Short-Term IDR	F2		Affirmed 29 March 2018
Senior Secured Debt	A–		Affirmed 29 March 2018
Senior Unsecured Debt	BBB+		Affirmed 29 March 2018
CP	F2		Affirmed 29 March 2018

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Financial Summary

(USD Mil.)	Dec 2014	Dec 2015	Dec 2016	Dec 2017
Gross Revenue	1,937	1,787	1,851	1,918
Operating EBITDAR	410	433	477	498
Cash Flow from Operations	387	315	389	470
Capital Intensity (Capex/Revenue) (%)	28.0	33.1	27.7	29.2
Total Adjusted Debt With Equity Credit	1,451	1,612	1,748	1,886
FFO Fixed-Charge Coverage (x)	5.6	5.0	5.5	5.6
FFO-Adjusted Leverage (x)	3.0	3.5	3.3	3.6
Total Adjusted Debt/Operating EBITDAR (x)	3.5	3.7	3.7	3.8

Source: Fitch Solutions.

Southwestern Public Service Company's (SPS) Long-Term Issuer Default Rating (IDR) primarily reflects the utility's low-risk regulated electric operations, challenging regulatory environment and somewhat leveraged financial profile.

Key Rating Drivers

Challenging Regulatory Environment: Fitch Ratings considers the regulatory environment overseen by the Public Utility Commission of Texas (PUCT) and the New Mexico Public Regulation Commission (NMPRC) to be challenging. Electric utilities in Texas and New Mexico have historically received authorized ROEs that are slightly lower than the nationwide average. In addition, regulatory lag from the use of a historical test year in Texas and other factors in the rate-setting process in New Mexico have made it difficult for SPS to earn its low authorized ROEs.

Supportive rate design mechanisms in both states include fuel and purchased power recovery mechanisms and riders for energy efficiency program costs. SPS also has riders for distribution costs and transmission infrastructure improvement costs in Texas and for renewable energy program costs in New Mexico.

New Mexico 2016 Electric Rate Case: The NMPRC dismissed SPS's electric rate case on April 19, 2017, claiming that the rate filing was deficient. SPS filed a notice of appeal to the New Mexico Supreme Court on May 15, 2017, with a decision not expected until second-half 2019. SPS filed its electric rate case on Nov. 1, 2016, seeking a $41.4 million non-fuel electric base rate increase. The requested increase was based on a future test year ending June 30, 2018 and a 10.1% authorized ROE.

New Mexico 2017 Electric Rate Case: SPS filed a rate case with the NMPRC in October 2017, seeking a $42.5 million rate increase. The requested rate increase was based on a historical test year ending June 30, 2017, a 10.25% ROE and a 53.97% equity ratio. SPS revised its rate request in May 2018 to incorporate the negative impact of tax reform, seeking a $27 million rate increase based on a 58% equity ratio. An NMPRC decision and implementation of final rates is expected in second-half 2018.

Texas 2017 Electric Rate Case: SPS filed a rate case with the PUCT in August 2017, seeking a net increase of $54.6 million, or 5.8%. SPS requested increasing its equity ratio to 58% from 53.97% in February 2018 to help offset the negative impact of tax reform. A settlement between SPS, the PUCT staff and various intervenors was reached on June 29, 2018, resulting in no overall change to revenues after incorporating the negative impact of tax reform. SPS would be able to increase its equity ratio to 57% and use a 9.5% ROE for the calculation of allowance for funds used during construction. A PUCT decision is expected in third-quarter 2018, with rates effective retroactive to Jan. 23, 2018.

Large Capex Plan: SPS has a large capex plan, with annual spending that has nearly doubled since 2012. Significant spending is associated with management's "steel for fuel" renewable energy investment strategy, with a focus on wind generation and electric transmission investments in New Mexico that are regulated by the Federal Energy Regulatory Commission. Capex is expected to average nearly $800 million per year over 2018–2022.

Tax Reform: Fitch expects tax reform to negatively affect SPS's EBITDA and FFO, particularly in the near term. SPS's financial metrics will also be pressured in the near term due to the utility's large capex plan and significant regulatory lag in recovering invested capital. Fitch expects SPS's financial profile to remain adequate for existing ratings, pending constructive outcome in regulatory proceedings, with FFO fixed-charge coverage forecast to average 5.5x–6.0x, FFO-adjusted leverage 4.5x–4.9x and adjusted debt/EBITDAR 4.5x–4.9x through 2020.

Rating Derivation Relative to Peers

Rating Derivation Versus Peers	
Peer Comparison	SPS's 'BBB' Long-Term IDR is appropriately positioned relative to its peers. The challenging regulatory environment in New Mexico and Texas results in a considerably weaker credit profile for SPS relative to that of its sister utilities Public Service Company of Colorado (PSCo; A–/Stable), Northern States Power Company-Minnesota (NSP-Minnesota; A–/Stable) and Northern States Power Company-Wisconsin (NSP-Wisconsin; A–/Stable). Compared with Public Service Company of Oklahoma (PSO, BBB/Stable), SPS has slightly stronger financial metrics, but PSO benefits from a relatively constructive regulatory environment that mitigates concerns about its large capex plan. Adjusted debt/EBITDAR and FFO-adjusted leverage at SPS were 4.2x and 4.0x, respectively, in 2017, compared with 4.8x and 4.7x at PSO.
Parent/Subsidiary Linkage	There is a weak rating linkage between the Long-Term IDR of SPS and that of its parent, Xcel Energy Inc. (Xcel; BBB+/Stable). Fitch allows for up to a two-notch differential between the Long-Term IDRs of Xcel and any of its utility subsidiaries.
Country Ceiling	No Country Ceiling constraint was in effect for these ratings.
Operating Environment	No operating environment influence was in effect for these ratings.
Other Factors	Not applicable.

Source: Fitch Solutions.

Navigator Peer Comparison

Issuer		Business profile						Financial profile		
Name	IDR/Outlook	Operating Environment	Management and Corporate Governance	Regulation	Market and Franchise	Asset Base and Operations	Commodity Exposure	Profitability	Financial Structure	Financial Flexibility
Southwestern Public Service Company	BBB/Sta	aa	a-	bbb-	bbb+	bbb	bbb	bbb	bbb+	bbb+
Public Service Company of Oklahoma	BBB/Sta	aa	a-	bbb	bbb+	bbb	bbb+	bbb	bbb	bbb+
Sierra Pacific Power Company d/b/a NV Energy	BBB/Pos	aa	a-	bbb+	bbb+	bbb+	bbb+	bbb	bbb+	a-
Nevada Power Company dba NV Energy	BBB/Pos	aa	a-	bbb+	bbb+	bbb+	bbb+	bbb	bbb+	bbb+

Source: Fitch — Importance: Higher, Moderate, Lower

Rating Sensitivities

Future Developments That May, Individually or Collectively, Lead to a Positive Rating Action

- Given the large capex plan and challenging regulatory environment, a positive rating action is unlikely in the near term. Over the longer term, a positive rating action could occur if regulatory lag were to improve materially and if Fitch were to expect adjusted debt/EBITDAR to remain less than 4.0x and FFO-adjusted leverage to remain less than 4.5x on a sustained basis.

Future Developments That May, Individually or Collectively, Lead to a Negative Rating Action

- Materially unfavorable regulatory developments;
- Adjusted debt/EBITDAR and FFO-adjusted leverage expected to exceed 4.7x and 5.3x, respectively, on a sustained basis;
- A shift in management strategy that results in weaker financial support from Xcel.

Liquidity and Debt Structure

Adequate Liquidity: Fitch considers the liquidity for Xcel and its utility subsidiaries to be adequate.

Xcel and its utility subsidiaries primarily meet their short-term liquidity needs through the issuance of CP under an aggregate $2.75 billion revolving credit facility (RCF) that expires in June 2021. Under the RCF, Xcel has a $1 billion borrowing sublimit at the parent, PSCo has a $700 million borrowing sublimit, NSP-Minnesota has a $500 million borrowing sublimit, SPS has a $400 million borrowing sublimit and NSP-Wisconsin has a $150 million borrowing sublimit.

Xcel and its utility subsidiaries had an aggregate $525 million of CP issued and $31 million of LOC drawn as of March 31, 2018, leaving an aggregate of $2.194 billion of availability under the five-year unsecured RCF. PSCo had $601 million of availability, NSP-Minnesota had $475 million of availability, SPS had $388 million of availability and NSP-Wisconsin had $128 million of availability.

Xcel has a 364-day term loan agreement expiring Dec. 4, 2018 that allows it to borrow up to $500 million. Xcel had borrowed $500 million as of March 31, 2018.

Liquidity is also available to PSCo, NSP-Minnesota and SPS through participation in an intercompany money pool. Borrowing limits are set at $250 million for PSCo, $250 million for NSP-Minnesota and $100 million for SPS. PSCo had $48 million of borrowings under the money pool as of March 31, 2018. NSP-Wisconsin is not a participant in the money pool.

Xcel and its utility subsidiaries require modest cash on hand. Xcel had $116 million of unrestricted cash and cash equivalents at March 31, 2018.

SPS does not have any long-term debt maturities over the next five years.

Debt Maturities and Liquidity

Scheduled Long-Term Debt Maturities	(USD Mil.)
2018	0
2019	0
2020	0
2021	0
2022	0
Thereafter	1,850
Total Long-Term Debt	1,850

Source: Fitch Solutions, company filings.

Liquidity Summary at March 31, 2018	(USD Mil.)
Unrestricted Cash & Cash Equivalents	4
Committed Bank Facilities	400
Money Pool Borrowing Limit	100
Short-Term Borrowings	10
Letters of Credit Outstanding	2
Availability Under Bank Facilities and Money Pool	488
Total Liquidity	492

Source: Fitch Solutions, company filings.

Key Assumptions

Fitch's key assumptions within our rating case for SPS include:

- Rate base CAGR of 12.2% from 2017 to 2022;
- Capex of $3.9 billion over 2018–2022;
- Rate case outcomes consistent with historical rate orders.

Financial Data

(USD Mil.)	Historical			
	Dec 2014	Dec 2015	Dec 2016	Dec 2017
SUMMARY INCOME STATEMENT				
Gross Revenue	1,937	1,787	1,851	1,918
Revenue Growth (%)	13.5	-7.7	3.6	3.6
Operating EBIT	266	274	308	297
Operating EBIT Margin (%)	13.7	15.3	16.6	15.5
Operating EBITDA Margin (%)	20.9	23.9	25.4	25.6
Rental Expense	-6	-6	-6	-7
DETAILED CASH FLOW STATEMENT				
FFO Margin (%)	20.2	20.6	23.2	22.7
Operating EBITDA	404	427	471	491
Cash Interest	-80	-85	-89	-86
Cash Tax	43	-24	61	42
Funds Flow From Operations	392	368	429	435
Change in Working Capital	-5	-53	-40	35
Cash Flow From Operations	387	315	389	470
Capex	-543	-592	-513	-560
Common Dividends	-83	-101	-85	-109
FCF	-239	-378	-209	-198
Net Acquisitions and Divestitures	0	0	0	0
Net Equity Proceeds	160	215	66	144
Net Debt Proceeds	79	160	130	121
Total Change in Cash	0	0	0	10

(USD Mil.)	Historical			
	Dec 2014	Dec 2015	Dec 2016	Dec 2017
SUMMARY BALANCE SHEET				
Readily Available Cash and Equivalents	1	1	1	11
Total Debt With Equity Credit	1,403	1,565	1,700	1,830
Off-Balance-Sheet Debt	48	47	48	56
Total Adjusted Debt with Equity Credit	1,451	1,612	1,748	1,886
COVERAGE RATIOS				
FFO Interest Coverage (x)	5.9	5.3	5.8	6.0
Operating EBITDA/Interest Paid (x)	5.1	5.0	5.3	5.7
FFO Fixed-Charge Coverage (x)	5.6	5.0	5.5	5.6
Operating EBITDAR/Interest Paid + Rents (x)	4.8	4.8	5.0	5.3
LEVERAGE RATIOS				
Total Debt with Equity Credit/Operating EBITDA (x)	3.5	3.7	3.6	3.7
Total Adjusted Debt/Operating EBITDAR (x)	3.5	3.7	3.7	3.8
FFO-Adjusted Leverage (x)	3.0	3.5	3.3	3.6

Rating Navigator

Southwestern Public Service Company

Corporates Ratings Navigator
US Utilities

FitchRatings

Southwestern Public Service Company

Corporates Ratings Navigator
US Utilities

Operating Environment

aa+	Economic Environment	aa	Very strong combination of countries where economic value is created and where assets are located.
aa	Financial Access	aa	Very strong combination of issuer specific funding characteristics and of the strength of the relevant local financial market.
	Systemic Governance	aa	Systemic governance (eg rule of law, corruption; government effectiveness) of the issuer's country of incorporation consistent with 'aa'.
b-			
ccc			

Regulation

bbb+	Degree of Transparency and Predictability	bb	Poor or uncertain track record of regulation and high political interference.
bbb	Timeliness of Cost Recovery	bb	Significant lag to recover capital and operating costs.
bbb-	Trend in Authorized ROEs	bbb	Average authorized ROE.
bb+	Mechanisms Available to Stabilize Cash Flows	bbb	Revenues partially insulated from variability in consumption.
bb	Mechanisms Supportive of Creditworthiness	bbb	Effective regulatory ring-fencing or minimum creditworthiness requirements.

Asset Base and Operations

a-	Diversity of Assets	bbb	Good quality and/or reasonable scale diversified assets.
bbb+	Operations Reliability and Cost Competitiveness	bbb	Reliability and cost of operations at par with industry averages.
bbb	Exposure to Environmental Regulations	bbb	Limited or manageable exposure to environmental regulations.
bbb-	Capital and Technological Intensity of Capex	bbb	Moderate reinvestments requirements in established technologies.
bb+			

Profitability

a-	Free Cash Flow	bbb	Structurally neutral to negative FCF across the investment cycle.
bbb+	Volatility of Profitability	bbb	Stability and predictability of profits in line with utility peers.
bbb			
bbb-			
bb+			

Financial Flexibility

a	Financial Discipline	a	Clear commitment to maintain a conservative policy with only modest deviations allowed.
a-	Liquidity	a	Very comfortable liquidity. Well-spread maturity schedule of debt. Diversified sources of funding.
bbb+	FFO Fixed Charge Cover	bbb	4.5x
bbb			
bbb-			

Management and Corporate Governance

a+	Management Strategy	a	Coherent strategy and good track record in implementation.
a	Governance Structure	bbb	Good CG track record but effectiveness/independence of board less obvious. No evidence of abuse of power even with ownership concentration.
a-	Group Structure	a	Group structure shows some complexity but mitigated by transparent reporting.
bbb+	Financial Transparency	a	High quality and timely financial reporting.
bbb			

Market and Franchise

a	Market Structure	bbb	Established market structure but some level of uncertainty in price-setting mechanisms.
a-	Consumption Growth Trend	a	Economically vibrant market or service territory with strong sales growth.
bbb+	Customer Mix	bbb	Less diversified customer base.
bbb	Geographic Location	bbb	Beneficial location or reasonable locational diversity.
bbb-	Supply Demand Dynamics	bbb	Moderately favorable outlook for prices/rates.

Commodity Exposure

a-	Ability to Pass Through Changes in Fuel	bbb	Limited exposure to changes in commodity costs.
bbb+	Underlying Supply Mix	bbb	Low variable costs and moderate flexibility of supply.
bbb	Hedging Strategy	a	Highly captive supply and customer base.
bbb-			
bb+			

Financial Structure

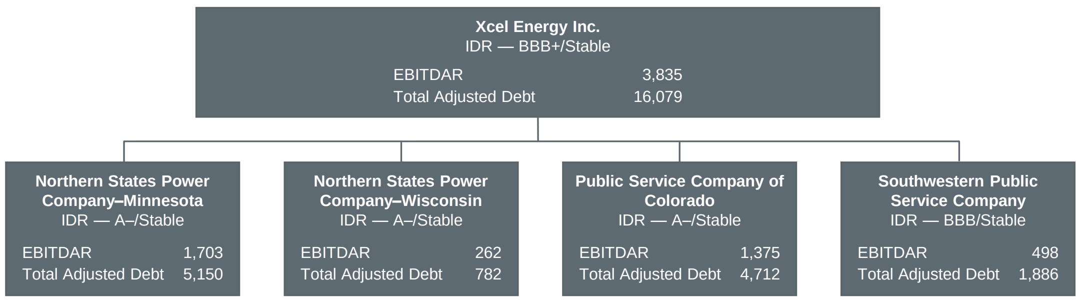
a	Lease Adjusted FFO Gross Leverage	a	3.5x
a-	Total Adjusted Debt/Operating	bbb	3.75x
bbb+			
bbb			
bbb-			

How to Read This Page: The left column shows the three-notch band assessment for the overall Factor, illustrated by a bar. The right column breaks down the Factor into Sub-Factors, with a description appropriate for each Sub-Factor and its corresponding category.

Navigator Version: RN 1.42.2.0

Simplified Group Structure Diagram

Organizational Structure — Xcel Energy Inc.
($ Mil., As of Dec. 31, 2017)



IDR – Issuer Default Rating.
Source: Company filings, Fitch Solutions.

Peer Financial Summary

Company	Date	Rating	Gross Revenue (USD Mil.)	Funds Flow From Operations (USD Mil.)	FFO Fixed-Charge Coverage (x)	FFO-Adjusted Leverage (x)	Total Adjusted Debt/Operating EBITDAR (x)
Southwestern Public Service Company	2017	BBB	1,918	435	5.6	3.6	3.8
	2016	BBB	1,851	429	5.5	3.3	3.7
	2015	BBB	1,787	368	5.0	3.5	3.7
Public Service Company of Oklahoma	2017	BBB	1,427	244	4.7	4.7	4.8
	2016	BBB	1,250	202	4.4	5.3	4.1
	2015	BBB	1,339	328	5.6	3.4	4.2
Sierra Pacific Power Company d/b/a NV Energy	2017	BBB	812	221	5.7	4.4	3.8
	2016	BBB	812	239	5.0	4.0	4.0
	2015	BBB	947	309	5.5	3.3	4.1
Nevada Power Company dba NV Energy	2017	BBB	2,206	702	4.7	3.5	3.6
	2016	BBB	2,083	662	4.3	3.7	3.5
	2015	BBB	2,402	969	5.8	2.9	3.7

Source: Fitch Solutions.

Reconciliation of Key Financial Metrics

(USD Millions, As reported)	31 Dec 2017
Income Statement Summary	
Operating EBITDA	491
+ Recurring Dividends Paid to Non-controlling Interest	0
+ Recurring Dividends Received from Associates	0
+ Additional Analyst Adjustment for Recurring I/S Minorities and Associates	0
= Operating EBITDA After Associates and Minorities (k)	**491**
+ Operating Lease Expense Treated as Capitalised (h)	**7**
= Operating EBITDAR after Associates and Minorities (j)	**498**
Debt & Cash Summary	
Total Debt with Equity Credit (l)	**1,830**
+ Lease-Equivalent Debt	56
+ Other Off-Balance-Sheet Debt	0
= Total Adjusted Debt with Equity Credit (a)	**1,886**
Readily Available Cash [Fitch-Defined]	11
+ Readily Available Marketable Securities [Fitch-Defined]	0
= Readily Available Cash & Equivalents (o)	**11**
Total Adjusted Net Debt (b)	**1,875**
Cash-Flow Summary	
Preferred Dividends (Paid) (f)	**0**
Interest Received	2
+ Interest (Paid) (d)	**(86)**
= Net Finance Charge (e)	**(84)**
Funds From Operations [FFO] (c)	**435**
+ Change in Working Capital [Fitch-Defined]	35
= Cash Flow from Operations [CFO] (n)	**470**
Capital Expenditures (m)	**(560)**
Multiple applied to Capitalised Leases	**8.0**
Gross Leverage	
Total Adjusted Debt / Op. EBITDAR* [x] (a/j)	**3.8**
FFO Adjusted Gross Leverage [x] (a/(c-e+h-f))	**3.6**
Total Adjusted Debt/(FFO - Net Finance Charge + Capitalised Leases - Pref. Div. Paid)	
Total Debt With Equity Credit / Op. EBITDA* [x] (l/k)	**3.7**
Net Leverage	
Total Adjusted Net Debt / Op. EBITDAR* [x] (b/j)	**3.8**
FFO Adjusted Net Leverage [x] (b/(c-e+h-f))	**3.6**
Total Adjusted Net Debt/(FFO - Net Finance Charge + Capitalised Leases - Pref. Div. Paid)	
Total Net Debt / (CFO - Capex) [x] ((l-o)/(n+m))	**-20.3**
Coverage	
Op. EBITDAR / (Interest Paid + Lease Expense)* [x] (j/-d+h)	**5.3**
Op. EBITDA / Interest Paid* [x] (k/(-d))	**5.7**
FFO Fixed Charge Cover [x] ((c-e+h-f)/(-d+h-f))	**5.6**
(FFO - Net Finance Charge + Capit. Leases - Pref. Div Paid) / (Gross Int. Paid + Capit. Leases - Pref. Div. Paid)	
FFO Gross Interest Coverage [x] ((c-e-f)/(-d-f))	**6.0**
(FFO - Net Finance Charge - Pref. Div Paid) / (Gross Int. Paid - Pref. Div. Paid)	

* EBITDA/R after Dividends to Associates and Minorities

Source: Fitch Solutions, based on information from company reports.

Fitch Adjustment Reconciliation

	Reported Values 31 Dec 17	Sum of Fitch Adjustments	Adjusted Values
Income Statement Summary			
Revenue	1,918	0	1,918
Operating EBITDAR	498	0	498
Operating EBITDAR after Associates and Minorities	498	0	498
Operating Lease Expense	7	0	7
Operating EBITDA	491	0	491
Operating EBITDA after Associates and Minorities	491	0	491
Operating EBIT	297	0	297
Debt & Cash Summary			
Total Debt With Equity Credit	1,830	0	1,830
Total Adjusted Debt With Equity Credit	1,886	0	1,886
Lease-Equivalent Debt	56	0	56
Other Off-Balance Sheet Debt	0	0	0
Readily Available Cash & Equivalents	11	0	11
Not Readily Available Cash & Equivalents	0	0	0
Cash-Flow Summary			
Preferred Dividends (Paid)	0	0	0
Interest Received	2	0	2
Interest (Paid)	(76)	(10)	(86)
Funds From Operations [FFO]	435	0	435
Change in Working Capital [Fitch-Defined]	35	0	35
Cash Flow from Operations [CFO]	470	0	470
Non-Operating/Non-Recurring Cash Flow	(0)	0	(0)
Capital (Expenditures)	(560)	0	(560)
Common Dividends (Paid)	(109)	0	(109)
Free Cash Flow [FCF]	(198)	0	(198)
Gross Leverage			
Total Adjusted Debt / Op. EBITDAR* [x]	3.8		3.8
FFO Adjusted Leverage [x]	3.7		3.6
Total Debt With Equity Credit / Op. EBITDA* [x]	3.7		3.7
Net Leverage			
Total Adjusted Net Debt / Op. EBITDAR* [x]	3.8		3.8
FFO Adjusted Net Leverage [x]	3.6		3.6
Total Net Debt / (CFO - Capex) [x]	-20.3		-20.3
Coverage			
Op. EBITDAR / (Interest Paid + Lease Expense)* [x]	6.0		5.3
Op. EBITDA / Interest Paid* [x]	6.5		5.7
FFO Fixed Charge Coverage [x]	6.2		5.6
FFO Interest Coverage [x]	6.7		6.0

*EBITDA/R after Dividends to Associates and Minorities
Source: Fitch Solutions.

Full List of Ratings

	Rating	Outlook	Last Rating Action
Southwestern Public Service Company			
Long-Term IDR	BBB	Stable	Affirmed 29 March 2018
Short-Term IDR	F2		Affirmed 29 March 2018
Senior Secured Debt	A–		Affirmed 29 March 2018
Senior Unsecured Debt	BBB+		Affirmed 29 March 2018
CP	F2		Affirmed 29 March 2018

Related Research & Criteria

Northern States Power Company-Minnesota (Subsidiary of Xcel Energy Inc.) (July 2018)
Northern States Power Company-Wisconsin (Subsidiary of Xcel Energy Inc.) (July 2018)
Public Service Company of Colorado (Subsidiary of Xcel Energy Inc.) (July 2018)
Xcel Energy Inc. (April 2018)
Fitch Affirms Xcel Energy and Subs' Ratings; Outlook Stable (March 2018)
Corporate Rating Criteria (March 2018)
Corporates Notching and Recovery Ratings Criteria (March 2018)
Parent and Subsidiary Rating Linkage (February 2018)

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The ratings above were solicited and assigned or maintained at the request of the rated entity/issuer or a related third party. Any exceptions follow below.

S&P Global
Market Intelligence

September 5, 2018
spglobal.com/marketintelligence

RRA Financial Focus
Xcel Energy Inc. (XEL)

- Recent decisions on the regulatory front regarding Xcel Energy's renewable energy investment program augur well for the company to achieve its stated financial objectives, including long-term annual EPS growth of 5% to 6%, annual dividend increases between 5% and 7% and a dividend payout ratio between 60% and 70%.

- As of early August, renewable energy and electric distribution and transmission spending among the company's rate-regulated utilities comprise more than two-thirds of Xcel Energy's $18.5 billion base capital expenditure plan for the 2018-2022 period. The Colorado Public Utilities Commission, or CPUC, on Aug. 27 voiced its support for the company's proposed Colorado Energy Plan, which could boost XEL's CapEx plan by approximately $1 billion, with new investments in wind, solar and natural gas generation and battery storage in the state.

- XEL envisions a companywide 60% CO_2 emission reduction from 2005 levels by 2030. Coal-fired capacity is expected to decline to an estimated 22% of the company's energy mix by 2027 from 37% in 2017, while the renewable energy share is expected to increase to 45% from 23% over the same time frame.

- Xcel Energy's finances have been fairly strong in recent years. Senior unsecured debt at XEL is rated BBB+ by S&P Global Ratings, and the secured ratings at its utilities are generally in the "A" category. The company's fixed charge and interest coverage ratios generally rank close to its industry peers, while the dividend coverage ratio ranks slightly stronger than peer levels.

- The XEL shares outperformed the average of the companies in the RRA electric utility group in 2017 by a considerable margin of +18% versus +8%, but are slightly underperforming year-to-date. Based on the S&P Global Market Intelligence consensus EPS estimate of $2.75 for 2020, the XEL shares are trading in line with the RRA electric group price-to-earnings multiple of approximately 17x and below the electric and gas utility group P/E of approximately 18x.

Xcel Energy is a major U.S. electric and natural gas company, with annual revenues of more than $11 billion. Based in Minneapolis, Minn., Xcel Energy operates in eight states. The company provides a comprehensive portfolio of energy-related products and services to 3.6 million electricity customers and 2.0 million natural gas customers. The company's primary subsidiaries are Northern States Power-Minnesota, Northern States Power-Wisconsin, Public Service Co. of Colorado and Southwestern Public Service.

Pricing information

Price as of 08/31/18	$48.05
Shares outstanding (000s)	509,087
Market cap. ($M)	$24,462
Market/book	210%
Return on equity	11.1%

Consensus earnings

Year ended	EPS	P/E
06/30/18	$2.48	19.4
12/31/18E	$2.45	19.6
12/31/19E	$2.60	18.5
12/31/20E	$2.75	17.5
5-year hist. growth		4.8%
3-year forecast growth		6%

Credit ratings: HoldCo

	Sr. Unsec	LT Issuer
S&P Global	BBB	A-
Moody's	A3	A3

Dividend

Rate	Yield	Payout
$1.52	3.2%	61%

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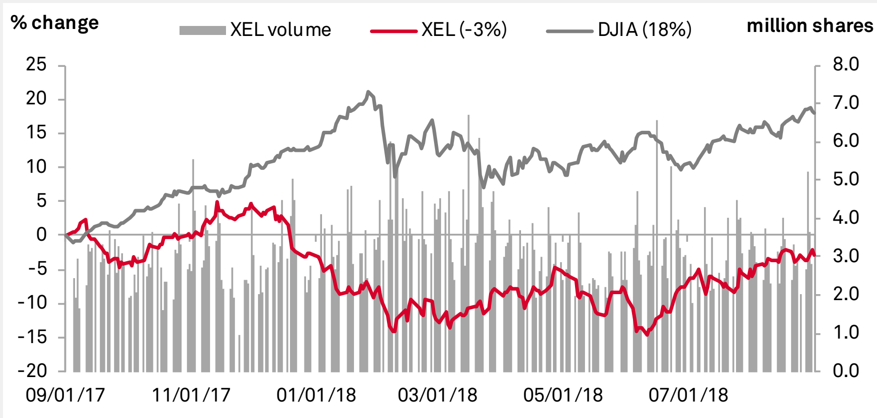
S&P Global
Market Intelligence

Financial Focus Company Report

XEL stock price performance LTM (%)



Through August 31, 2018
Source: S&P Global Market Intelligence

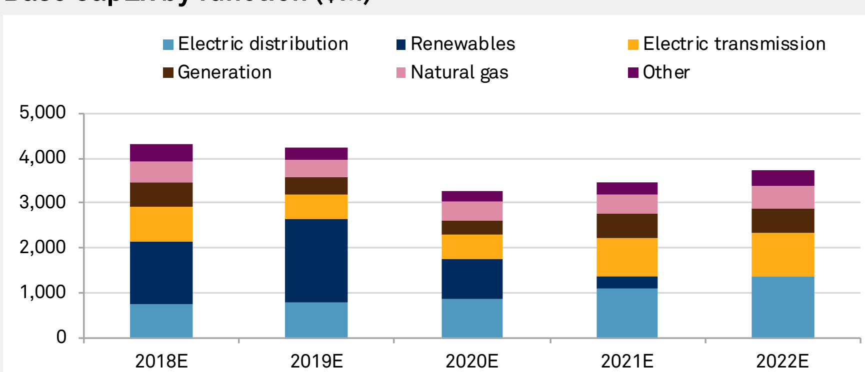
Summary

Consistent with its long-term strategy to invest in its vertically integrated utilities to drive rate base and EPS growth, Xcel Energy is targeting a multibillion-dollar capital plan over the next several years that will see spending weighted toward electric distribution and transmission, new renewable and gas-fired generation and advanced grid investments.

With 3.6 million electricity customers and 2.0 million natural gas customers, Xcel Energy is one of the largest combination utilities in the U.S. The company is vertically integrated in all of its jurisdictions and subject to traditional cost-of-service regulation by state regulators. The company's four principal utilities are Northern States Power-Minnesota, or NSP-M; Northern States Power-Wisconsin, or NSP-W; Public Service Co. of Colorado, or PSCo; and Southwestern Public Service Co., or SPS.

Over the five years 2018 through 2022, Xcel Energy estimates that capital spending will total $18.5 billion, with $4.21 billion in 2018, $4.13 billion in 2019, $3.16 billion in 2020, $3.36 billion in 2021, and $3.64 billion in 2022. Roughly half will be directed toward electric distribution and renewable energy investments. Note that Xcel Energy's base capital plan does not include approximately $1 billion of proposed investments in Colorado, which received regulatory approval on Aug. 27 (see below for further discussion).

Base CapEx by function ($M)



Source: Xcel Energy

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With aggressive state renewable portfolio standards in its operating regions, Xcel Energy's "steel-for-fuel", i.e., wind turbines, strategy calls for more than 3,500 MW of owned wind energy to be added across the company's utility service territories by the end of 2020. Capital recovery costs associated with the projects are expected to be offset by the absence of fuel charges, lower operation and maintenance costs than other sources of generation, and production tax credits, or PTCs.

Earlier this year, the Public Utility Commission of Texas and the New Mexico Public Regulation Commission approved SPS's application to construct and operate the $865-million, 522-MW Sagamore Wind Project in Roosevelt County, N.M., and the $769-million, 478-MW Hale Community Energy facility in Hale County, Texas.

In New Mexico, SPS will file a rate case in 2019 and 2020 to recover the costs of the Hale and Sagamore projects, respectively. During the months those rate cases are considered, the expected benefits from the power market sales and PTCs will be counted toward offsetting the revenue requirements of the wind projects, therefore reducing the customer rates that are ultimately set in those proceedings.

In Texas, regulators concluded that SPS "has shown a probable lowering of costs" to its customers after the utility agreed to: impose a cap on the projects' capital costs; a minimum wind production guarantee for the purpose of calculating certain ratepayer benefits; credit ratepayers with 100% of the PTCs associated with the projects' output; and compensate customers if the costs of the Hale and Sagamore projects exceed the calculated savings to customers in the first 10 years of operation. SPS estimated its Texas retail customers will save $1.6 billion over the full service lives of the projects.

Xcel Energy wind projects

Project	Capacity (MW)	State	Estimated completion
Rush Creek	600	CO	2018
Freeborn	200	MN	2020
Blazing Star I	200	MN	2019
Blazing Star II	200	MN	2020
Lake Benton	100	MN	2019
Foxtail	150	ND	2019
Crowned Ridge	300	SD	2019
Dakota Range	300	SD	2021
Hale	478	TX	2020
Sagamore	522	NM	2020
Colorado Energy Plan	500	CO	2020
Total new ownership	**3,550**		
Existing ownership	**850**		
Total MW	**4,400**		

As of August 7, 2018.
Colorado Energy Plan is pending regulatory approval.
Source: Xcel Energy

Earnings, finances and peer analysis

Xcel Energy's operating EPS have trended upward over the past few years: $2.09 in 2015, $2.21 in 2016 and $2.30 in 2017. Operating EPS are forecast to grow 6.5% to $2.45 in 2018 according to the S&P Global Market Intelligence consensus estimate — slightly below the midpoint of management's guidance range of $2.41 to $2.51 as of Aug. 23 — and further to $2.60 and $2.75 in 2019 and 2020, respectively. The company's EPS growth objective is 5% to 6% annually, and dividend growth is targeted at 5% to 7% annually.

Factors contributing to the 4.1% EPS increase in 2017 were higher electric and natural gas margins to recover infrastructure investments, reduced operations and maintenance, or O&M, expenses, a lower effective tax rate and higher allowance for funds used during construction, or AFUDC.

Second-quarter 2018 EPS of $0.52 surpassed the S&P Global Market Intelligence consensus EPS estimate by approximately 11%, reflecting higher electric and natural gas margins and higher AFUDC, partially offset by O&M and interest expense.

Xcel Energy's finances have been fairly strong in recent years. Senior unsecured debt at XEL is rated BBB+ and A3 by S&P Global Ratings and Moody's, respectively. The secured ratings at NSP-M, NSP-W, PSCo and SWPS are generally in the "A" category. The company has increased its dividend in 15 consecutive years, with the most recent increases of 5.6%, 5.9% and 6.3% announced in February 2018, 2017 and 2016, respectively.

The company's fixed charge and interest coverage ratios generally rank close to its industry peers, while the dividend coverage ratio ranks slightly stronger than peer levels. XEL's earned return on equity of 11.1% for the 12 months ended June 30 is somewhat below the peer average of 11.73%. The company's dividend payout range target is 60% to 70%, and its current payout ratio is 63%.

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Peer comparison, financial metrics

Company	Ticker	ROE (%)	Dividend payout ratio (%)	Pretax interest coverage (x)	Fixed charge coverage (x)	Cash flow coverage of dividend (x)	Return on total capital (%)	Common equity ratio (%)
FirstEnergy	FE	19.70	48.48	3.00	1.71	5.25	5.06	27.96
Dominion Energy	D	15.48	80.89	2.83	3.00	2.22	4.42	31.23
CMS Energy	CMS	15.26	55.87	3.35	2.57	4.95	4.56	30.58
Entergy	ETR	13.41	58.42	3.53	2.61	6.43	4.21	30.74
NextEra Energy	NEE	11.51	58.53	3.34	3.44	2.82	4.93	48.04
DTE Energy	DTE	11.41	56.82	3.14	2.97	3.76	4.60	41.89
WEC Energy Group	WEC	11.25	64.03	3.96	3.50	2.83	5.15	47.15
Public Service Enterprise Group	PEG	11.24	58.67	4.43	4.66	2.87	5.34	49.70
Xcel Energy	XEL	11.10	58.87	3.67	2.98	4.45	4.43	40.88
Ameren	AEE	**10.85**	**56.29**	**4.32**	**3.00**	**4.86**	**4.78**	**44.78**
American Electric Power	AEP	**10.58**	**62.50**	**3.75**	**3.09**	**3.84**	**4.45**	**43.07**
Eversource Energy	ES	**9.13**	**61.64**	**4.16**	**3.21**	**3.54**	**3.94**	**43.95**
Consolidated Edison	ED	**8.79**	**65.96**	**3.13**	**2.74**	**3.62**	**3.95**	**46.62**
Avangrid Inc.	AGR	**4.49**	**78.55**	**2.31**	**3.39**	**2.33**	**3.19**	**70.92**
Average		**11.73**	**61.82**	**3.49**	**3.06**	**3.84**	**4.50**	**42.68**

As of, or for the 12 months that ended June 30, 2018.
Source: S&P Global Market Intelligence

Peer comparison, operating metrics

Company	Ticker	3-year beta	Institutional ownership (%)*	Hedge fund ownership (%)*	Avg. daily trading vol. (M)	Electric customers	Natural gas distribution customers	Regulated op cap (MW)	Merchant op cap (MW)
FirstEnergy	FE	0.17	89.76	15.47	4.94	6,087,000	-	4,386	11,669
Dominion Energy	D	0.24	68.72	1.47	3.60	2,588,084	2,330,553	23,204	3,303
CMS Energy	CMS	-0.18	92.03	4.58	2.47	1,826,000	1,776,000	5,921	1,163
Entergy	ETR	0.32	94.56	7.20	1.45	2,884,881	199,000	22,774	5,296
NextEra Energy	NEE	0.00	78.66	1.00	1.83	4,922,000	-	28,104	18,388
DTE Energy	DTE	0.03	72.09	2.78	1.13	2,200,000	1,300,000	11,861	522
WEC Energy Group	WEC	-0.20	74.29	1.45	1.75	1,607,500	2,868,500	9,618	75
Public Service Enterprise Group	PEG	0.14	70.34	2.28	3.07	2,200,000	1,800,000	275	12,037
Xcel Energy	XEL	-0.13	74.57	1.64	3.19	3,587,474	2,021,724	18,747	1
Ameren	AEE	0.07	70.71	5.47	1.49	2,400,000	900,000	11,117	NA
American Electric Power	AEP	-0.14	73.64	4.30	2.77	5,400,000	-	24,081	3,308
Eversource Energy	ES	0.09	76.87	2.87	1.95	3,187,126	524,628	94	1,080
Consolidated Edison	ED	-0.17	60.26	1.16	1.77	3,700,000	1,200,000	836	1,348
Avangrid Inc.	AGR	0.07	14.26	1.31	0.48	2,231,576	998,236	63	1,324

As of, or for the 12 months that ended June 30, 2018.
*Institutional ownership includes hedge fund ownership.
NA = Data is not available
Source: S&P Global Market Intelligence

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Xcel Energy utility operations

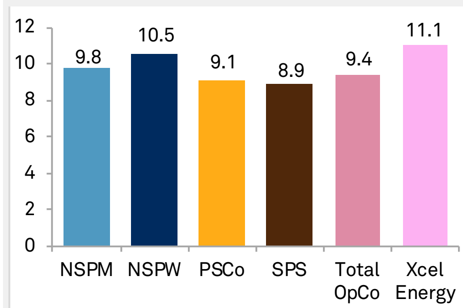
Regulated electric and gas utilities account for virtually all of XEL's operations, representing approximately 85% and 14.5% of 2017 operating revenues, respectively.

The July 2018 unemployment rate in Xcel Energy's operating states was somewhat mixed when compared with the U.S. average of 3.9%, ranging from 2.6% in North Dakota to 4.7% in New Mexico, with a 3.4% consolidated rate. Electric customer growth was 0.9% in both 2017 and 2016, while system-wide, total weather-adjusted electric sales growth in 2017 was marginal, though incremental growth was seen in the NSP-W and SPS service territories. Weather-adjusted natural gas sales grew 2.7% in 2017.

Northern States Power Co. – Minnesota

With 1.5 million electric customers and 0.5 million natural gas customers in portions of Minnesota and the Dakotas, NSP-M generally contributes 35% to 45% of Xcel Energy's consolidated earnings, and approximately $7.82 billion of base CapEx are planned between 2018 and 2022. RRA accords Minnesota and South Dakota Average/2 rankings, indicating the regulatory climate in those states is balanced from an investor perspective; North Dakota carries an Average/1 ranking, indicating the regulatory climate in the state is relatively balanced from an investor perspective.

Ongoing ROE (%)

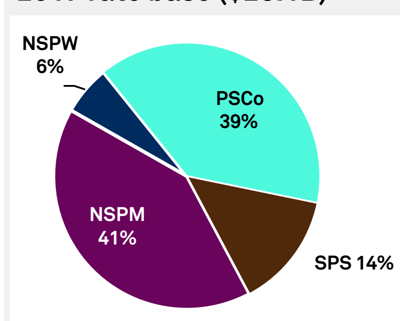


Source: Xcel Energy

The utility's most recent electric rate case was [decided in May 2017] when the Minnesota Public Utilities Commission, or MPUC, voted to approve a settlement providing for NSP-M to implement a $185 million or 6.1% multistep electric rate increase, including a $75 million rate increase effective retroactive to Jan. 1, 2016, and incremental rate increases of $59.9 million and $50.1 million effective in 2017 and 2019, respectively.

The company in November 2015 had filed for a $297.1 million, three-step permanent electric rate increase to fund projects that improve the company's distribution and transmission systems for continued reliability and the ability to integrate renewable energy and to allow the company to continue to deliver carbon-free energy from its nuclear plants.

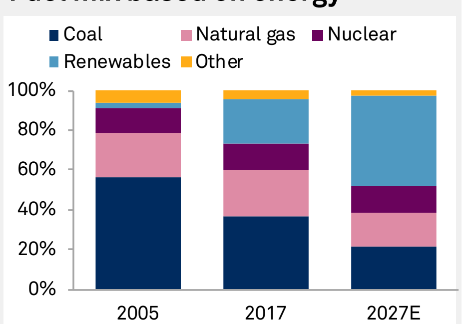
2017 rate base ($25.1B)



Source: Xcel Energy

On Aug. 9, MPUC [voted to order] several of the state's investor-owned utilities to return to ratepayers benefits from a reduction in the corporate income tax rate. The commission ordered NSP-M to flow to ratepayers approximately $130 million in annual tax benefits, of which $2 million is directed to increase funding for the POWER ON program to assist low-income customers.

Fuel mix based on energy



Source: Xcel Energy

The MPUC in July 2017 approved NSP-M's upper Midwest expansion plan entailing the addition of 1,550 MW of wind generation, of which 1,150 MW will be owned by NSP-M. The projects are slated to go online by the end of 2020 and will qualify for 100% of the PTC. The MPUC approved an aggregate capital cap for 750 MW of self-build projects, allowing NSP-M to include in rate base any savings versus a capital cost estimate for the projects. NSP-M would not recover capital costs in excess of the cap. The North Dakota Public Utility Commission is reviewing the proposal, and an order is expected later this year.

Public Service Co. of Colorado

PSCo generally accounts for 35% to 45% of Xcel Energy's consolidating earnings and serves 1.5 million and 1.4 million electric and gas customers, respectively. RRA accords Colorado regulation an Average/2 ranking, indicating the regulatory climate in the state is balanced from an investor perspective.

In Colorado, construction is underway on Public Service Co. of Colorado's, or PSCo's, 600-MW Rush Creek wind project. In 2016, the Colorado Public Utilities Commission granted PSCo a certificate to build the project, which includes a hard cost cap of about $1.10 billion and a capital cost sharing mechanism between customers and PSCo of 82.5% to customers and 17.5% to PSCo for every $10 million the project comes in below the cost cap. PSCo plans to seek cost recovery of the project upon completion.

On Aug. 27, the CPUC ordered staff to prepare a written order approving PSCo's Colorado Energy Plan, which will involve the retirement of units 1 and 2 of the coal-fired Comanche Generating Station with a capacity of 660 MW and $2.5 billion of renewable energy and battery storage investments.

In June, PSCo submitted its resource selections from its 2017 all-source solicitation to the CPUC. Based on the resource selections, Xcel Energy would add more than 1,100 MW of new wind generation — of which 500 MW would be owned by PSCo — about 700 MW of utility-scale solar generation, and 275 MW of large-scale battery storage and acquire 380 MW of gas-fired generation to provide reliability support for expanded renewables. All told, the investments are expected to save ratepayers at least $213 million. The commission will formalize its support in a written decision, which is due by Sept. 4.

PSCo plans approximately $6.18 billion of base capital expenditures between 2018 and 2022, though that figure is expected to rise by about $1 billion pending final approval of the company's Colorado Energy Plan.

On Aug. 29, the CPUC issued an order in PSCo's pending gas rate case, granting the company a $46.6 million interim rate increase, effective Sept. 1, subject to refund with interest, pending the commission's final decision in the case. After consideration of a $20 million tax-related adjustment previously agreed to by parties to the proceeding, ratepayers would see a $26.6 million net rate increase over previously approved permanent rates. This case was initiated June 2, 2017, when PSCo filed for a $232.9 million three-step permanent rate increase, citing rising costs coupled with flat or modestly increasing sales as the primary drivers necessitating the proposed rate hike. The CPUC is expected to issue an order addressing the company's July 24 filing in the near future. Interim rate increases of $63.2 million and $43.2 million were previously implemented in January and March, respectively.

Southwestern Public Service Co.

SPS serves 390,000 electric customers in portions of Texas and New Mexico, with the utility generally contributing 10% to 15% of Xcel Energy's consolidated earnings. RRA accords Texas an Average/3 ranking, indicating the regulatory climate in the state is relatively balanced from an investor perspective, while New Mexico carries a Below Average/2 ranking, indicating a less constructive, higher-risk regulatory climate from an investor viewpoint.

The utility has two pending electric rate cases in its Texas and New Mexico jurisdictions. On June 29, the hearing examiner assigned to SPS' case in New Mexico issued a recommended decision proposing that the company be accorded an $11.1 million or 5.1% base rate increase. The recommendation reflects the impact of federal tax reform that, effective Jan. 1, reduced the federal corporate income tax rate to 21% from 35%. On July 2, the hearing examiner issued an errata filing slightly modifying the recommended rate hike to $11.7 million or 5.3% based on the above noted return parameters. The filing did not specify an updated rate base amount. The case was initiated Oct. 27, 2017, when SPS filed for a $42.5 million rate increase, citing major capital additions, a reduction in wholesale power sales and proposed changes to the useful life of the Tolk Generating Station. The New Mexico Public Regulation Commission, or PRC, is expected to render a final decision in the proceeding by Dec. 31.

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In the Texas rate case, a settlement was reached on June 29 calling for no rate change and addressing tax-reform-related impacts. The settlement calls for base rates and the revenue requirement collected under the company's transmission cost recovery factor, or TCRF, to remain unchanged. SPS had proposed to roll in to base rates about $14.7 million that was being collected under the TCRF. A final Texas Public Utility Commission decision is due by Nov. 2 but may come sooner due to the settlement.

The proceeding was initiated Aug. 21, 2017, when SPS filed for an $80.9 million Texas-jurisdictional electric base rate increase. SPS indicated that the primary reasons for the filing were to achieve rate recognition of investments in infrastructure, reflect the revenue requirement impact of a reduction in wholesale power sales, and adjust depreciation rates among other items to reflect the shorter operating lives of the two units at the coal-fired Tolk generation facility, which are to be retired in 2032 rather than 2042 for unit 1 and 2045 for unit 2.

Xcel Energy Inc. most recent retail base rate decisions

Company	Juris.	Svc.	Case type	Decision	Rate change ($M)	ROR (%)	ROE (%)	Common eq. / total cap. (%)	Rate base ($M)
Northern States Power Co. - WI	WI	Electric	Vertically Integrated	12/07/17	9.4	7.56	9.80	51.45	1,194.8
Northern States Power Co. - WI	WI	Natural Gas	Distribution	12/07/17	9.9	7.56	9.80	51.45	137.7
Northern States Power Co. - MN	MN	Electric	Vertically Integrated	05/11/17	244.7	7.08	9.20	52.50	7,202.3
Northern States Power Co. - MN	MN	Natural Gas	Distribution	12/06/10	7.3	10.09	8.28	52.46	438.3
Northern States Power Co. - MN	SD	Electric	Vertically Integrated	06/15/15	15.2	7.22	NA	NA	412.4
Public Service Co. of Colorado	CO	Electric	Vertically Integrated	02/24/15	-39.4	9.83	7.55	50.00	NA
Public Service Co. of Colorado	CO	Natural Gas	Distribution	02/16/16	39.2	7.33	9.50	56.51	1,416.5
Southwestern Public Service Co.	NM	Electric	Vertically Integrated	08/10/16	23.5	NA	NA	NA	NA
Southwestern Public Service Co.	TX	Electric	Vertically Integrated	01/26/17	35.2	NA	NA	NA	NA

As of Aug. 24, 2018
NA = Value not specified
Source: S&P Global Market Intelligence

Xcel Energy Inc. pending rate cases

Company	Juris.	Svc.	Case type	Filing	Req. rate change ($M)	ROR (%)	ROE (%)	Common eq. / total cap. (%)	Rate base ($M)	Action likely by
Public Service Co. of Colorado	CO	Natural Gas	Distribution	06/02/17	232.9	7.49	10.00	55.25	2,434.8	12/31/18
Southwestern Public Service Co.	NM	Electric	Vertically Integrated	10/27/17	27.3	7.84	10.25	58.00	877.5	12/31/18
Southwestern Public Service Co.	TX	Electric	Vertically Integrated	08/21/17	32.0	7.79	10.25	58.00	1,882.9	11/02/18

As of Aug. 24, 2018
Source: S&P Global Market Intelligence

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Market Intelligence

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Electricity price trends

Regional wholesale electricity price trends may influence customer rates. Wholesale electricity prices are affected both by expected fuel price changes and the need for new generation in a region. While a customer's bill has a significant component for fixed transmission and distribution investment, generation and fuel typically account for 25% to 50%, respectively, of a customer's electricity rate, depending on the customer rate class and the amount of rate-based generation available to serve the customer.

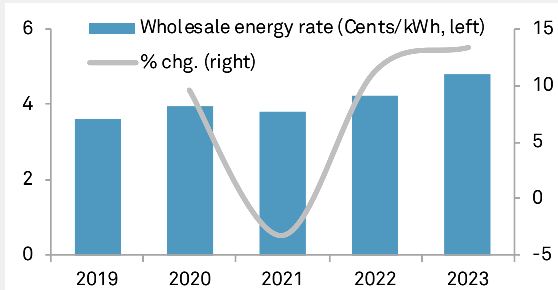
Xcel Energy owns roughly 8.8 GW of capacity in MISO, 7.4 GW of which is in Minnesota. Though coal and natural gas prices are expected to remain relatively stable, reserve margins are expected to tighten in the region, leading to an overall uplift in cleared capacity prices and new generation capital expenditures. Wholesale electricity rates at MISO's Minnesota Hub are forecast to increase 7.7% per year from 2019 to 2023, corresponding to a rate growth of 1.2 cents per kWh.

Xcel Energy owns about 4.5 GW of capacity in SPP, 3.8 GW of which is in Texas. Reserve margins in the region are expected to decline during the 2019-2021 period due to the retirement of coal-fired generation. Natural gas generation is available to replace regional retirements, but the relative competitiveness of the retired coal puts upward pressure on wholesale prices. Wholesale electricity rates at the SPP South Hub are forecast to increase 2.7% per year from 2019 to 2023, for a rate growth of 0.4 cents per kWh.

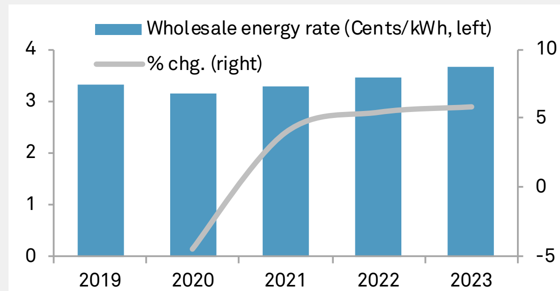
Finally, Xcel Energy owns about 5.5 GW of capacity in Colorado. The Four Corners hub is the closest regional power hub to Xcel's Colorado assets. Reserve margins in the SRSG region containing Four Corners are expected to shrink with the retirement of the coal-fired Navajo plant, and new generation will be needed to replace it. Wholesale electricity rates in the Four Corners region are forecast to increase 6.8% per year from 2019 to 2023, for a rate growth of 1.1 cents per kWh.

Charlotte Cox and Sara May Bellizzi contributed to this report.

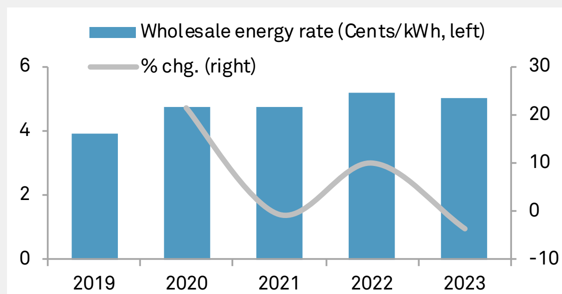
Minnesota Hub wholesale electric rate proj.



South Hub wholesale electric rate proj.

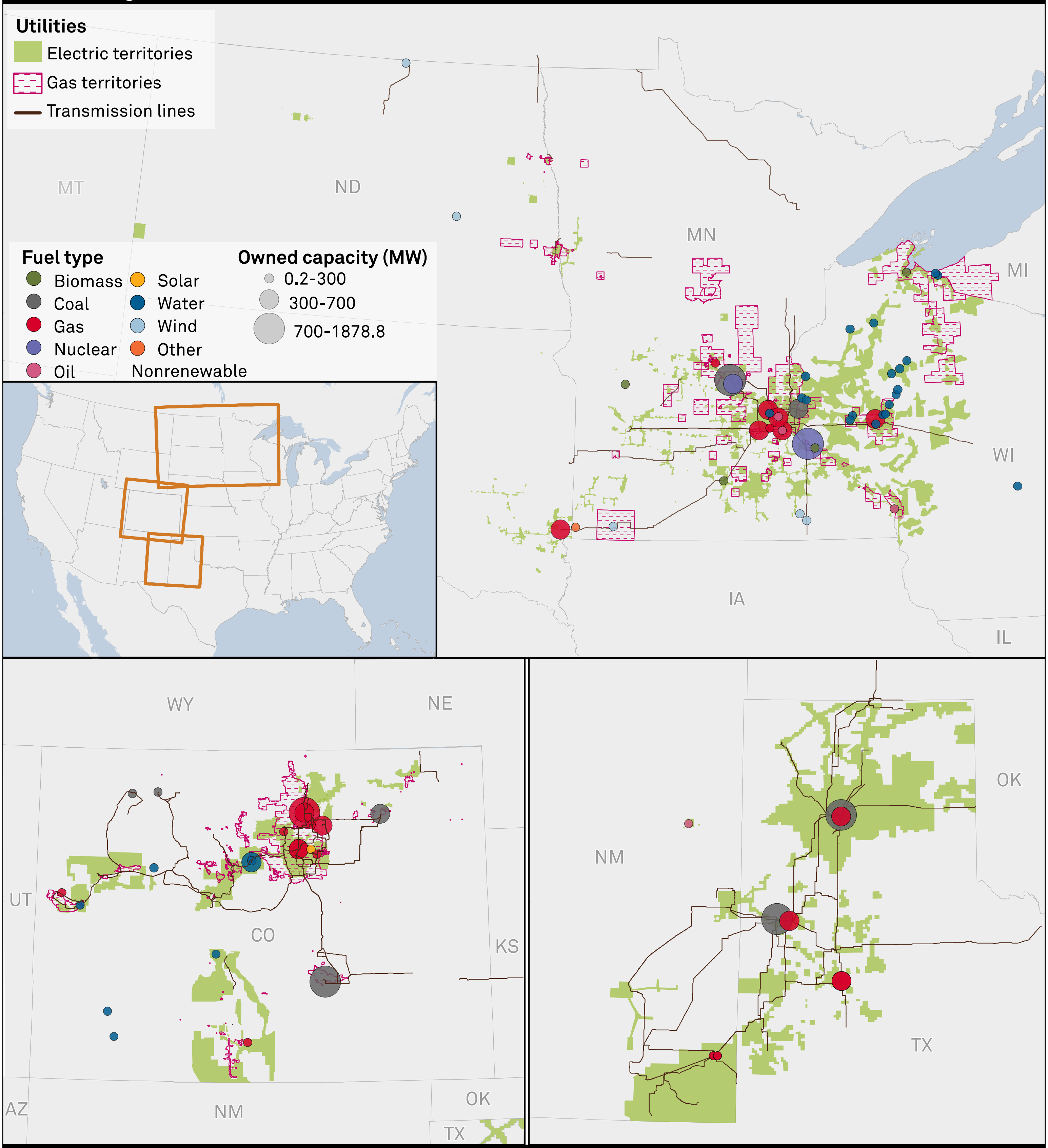


Four Corners wholesale electric rate proj.



As of June 30, 2018.
Source: S&P Global Market Intelligence

Xcel Energy Inc.



As of August 2018.
Map credit: Ciaralou Agpalo Palicpic
Source: S&P Global Market Intelligence

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New Mexico Public Regulation Commission

General Information

Contact Information	1120 Paseo De Peralta, PERA Building Santa Fe, NM 87501-1269 (888) 427-5772
	http://www.nmprc.state.nm.us
Number of Commissioners	5 of 5
Selection Method	Commissioners: Elected in statewide elections Chairperson: Elected by fellow Commissioners
Term of Office	Commissioners: 4 years Chairperson: 1 years
Chairperson of Commission	Theresa Becenti-Aguilar
Deputy Chairperson of Commission	Valerie Espinoza
Governor	Michelle Lujan Grisham (D)
Service Regulated	Electric cooperatives, Electric utilities, Gas utilities, Pipeline companies, Sewer utilities, Telecommunications utilities, Water utilities
Commission Ranking	Below Average/2 (5/10/2017)
Commission Budget	$13.90 million
Commissioner Salaries	Commissioners: $90,000 Chairperson: $90,000
Size of Commission Staff	155
Company Name, Abbreviated	New Mexico Public Regulation Commission's Rate Case History
Research Notes	RRA Articles
RRA Contact	Jim Davis

Commissioners

PERSON'S NAME	PARTY ABBREVIATION	DATE ROLE BEGAN	TERM ENDS
Theresa Becenti-Aguilar Chairman	D	01/2019	12/2022
Valerie Espinoza Vice Chairman	D	01/2013	12/2020
Cynthia Hall	D	01/2017	12/2020
Stephen Fischmann	D	01/2019	12/2022
Jefferson Byrd	R	01/2019	12/2022

RRA Ranking History

DATE OF RANKING CHANGE	COMMISSION RANKING
5/10/2017	Below Average / 2

DATE OF RANKING CHANGE	COMMISSION RANKING
4/1/2008	Below Average / 1
1/5/2004	Average / 3
4/7/2000	Average / 2
5/1/1993	Average / 3
8/1/1986	Average / 2
10/2/1984	Average / 1
7/2/1982	Above Average / 3

RRA maintains three principal rating categories for regulatory climates: Above Average, Average, and Below Average. Within the principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger rating; 2, a mid-range rating; and, 3, a weaker rating. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by the jurisdiction's utilities. The evaluation reflects our assessment of the probable level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative, and court actions.

Miscellaneous Issues

Commissioner election process/Commissioner criterion — One commissioner is elected from each of five geographic districts. Commissioners may not serve more than two consecutive terms; there are no limitations for non-consecutive terms of office. To qualify as a commissioner, elected or appointed PRC members are required to have at least 10 years of professional experience in areas regulated by the PRC or in the energy sector and involving accounting, public or business administration, economics, finance, statistics, engineering or law. The 10-year requirement can include the time frame by which the candidate earned a professional license or baccalaureate degree from an accredited institute of higher education in the above-mentioned areas. In addition, ethics certification and continuing education requirements are mandated by state law.

Commission membership — Commissioner Lyons was ineligible to run for re-election in 2018, after having served two consecutive terms. On Nov. 6, 2018, Jefferson Byrd, Theresa Becenti-Aguilar and Stephen Fischmann were elected to four year terms on the PRC that commence in January 2019. Jefferson Byrd, a Republican, was elected to the District 2 seat currently held by Commissioner Lyons. Theresa Becenti-Aguilar, a Democrat, was elected to the District 4 seat currently held by Commissioner Lovejoy. Stephen Fischmann, a Democrat, was elected to the District 5 seat currently held by Commissioner Jones.

Gubernatorial election — Gov. Martiznez is term limited and cannot run for a third consecutive term. Democrat Michelle Lujan Grisham and Republican Steve Pearce are the candidates running for the governor's office in the November 2018 election.

Services regulated — Investor-owned electric, gas, telecommunications, water, and sewer utilities; rural electric cooperatives; transportation companies; gas pipeline safety; and, the rates of water and sanitation districts. The state fire marshal is also under the jurisdiction of the PRC.

Staff contact: Dwight Lamberson, Director, Utility Division (505) 827-6960

(Section updated 11/8/18)

RRA Evaluation

Although the New Mexico regulatory climate had shown some signs of improvement in recent years, RRA views the state's regulatory environment as restrictive from an investor perspective. In recent rate case decisions, the PRC has authorized equity returns that have approximated prevailing industry averages at the time established. However, the state's utilities have typically failed to earn their authorized returns. While state law has permitted the use of fully forecasted test years in base rate proceedings since 2009, the first authorization of a future test year did not occur until 2014, and the practice of using test years with projected data remains a contested issue, as demonstrated by the PRC's outright rejection of three rate cases that sought to employ such information. While the future test year matter appeared to be resolved in 2015, after a contested test year ruling was withdrawn by the PRC while the decision was before the New Mexico Supreme Court on appeal, the PRC recently rejected another rate case filing over its use of a forecasted test year in April 2017. The decision to reject the rate application came nearly six months after the case was filed with the commission. The New Mexico utilities have fuel, purchase power and gas commodity clauses in place, but the PRC has yet to adopt a revenue decoupling mechanism for any utility. In addition, a modest attempt by the commission to ameliorate the impacts of conservation programs on utility revenues/earnings in the form of a directive that had permitted the electric utilities to charge a "rate adder" for each KWH conserved as a result of energy efficiency programs was overturned by the state Supreme Court. In May 2017, RRA performed a comprehensive audit of its regulatory rankings. The ranking accorded New Mexico was lowered as a result of this process. RRA now accords the state a Below Average/2 rating, versus the previous rating of Below Average/1. (Section updated 5/10/17)

Commission Staff

The PRC Staff consists of about 155 members, with roughly 25 allocated to the Utility Division (Section updated 1/2/15)

Consumer Interest

The Energy Unit of the Energy, Environment and Telecommunications Division of the Office of the Attorney General intervenes in major cases on behalf of residential and small business ratepayers. Prosperity Works intervenes on behalf of low-income customers and New Mexico Industrial Energy Consumers intervenes on behalf of large industrials in the state. (Section updated 1/2/15)

Rate Case Timing/Interim Procedures

The PRC must act to suspend proposed rates within 30 days of a rate filing or the tariffs become effective. If the Commission does not render a decision within 10 months of the filing, a requested increase may be placed into effect on a permanent basis. Subsequent Commission rulings are effective on a prospective basis only. The PRC can extend the suspension period an additional three months with cause. Interim rate increases have rarely been authorized; a utility must demonstrate that it will experience immediate and irreparable injury in the absence of interim rates. In 2011, the PRC denied Public Service Company of New Mexico's (PSNM's) request to implement an interim increase as per the terms of a stipulation in the company's then-pending rate case. The PRC indicated that PSNM could not demonstrate that the company would be subject to irreparable harm in the absence of the interim rate increase. PSNM is a subsidiary of PNM Resources.

In order to expedite the construction of new electric generation and transmission facilities in New Mexico, the PRC is required by law to rule on large generation plant (above 300 MW) and transmission line siting applications within nine months of filing. Failure to act within nine months serves as automatic approval. Under certain circumstances, the nine-month requirement may be extended for an additional six months. (Section updated 1/2/15)

Rate Base and Test Period

The PRC historically relied upon a year-end original-cost rate base for a historical test period, adjusted for known-and-measurable changes. However, 2009 legislation allows the PRC to use forecasted test periods. The first rate case that actually reflected a forecasted test year was decided in 2014. However, the case, involving Xcel Energy subsidiary Southwestern Public Service, was decided more than 15 months after the date of filing, and more than four months into the test year, thus reducing the effectiveness of the use of a future test year.

The PRC subsequently rejected two separate utility rate case applications in 2015 that utilized fully forecasted test years. In the same year, the commission issued an interpretive ruling in which the PRC determined that a test year containing projected data must commence within 45 days after a rate case filing. Several utilities subsequently appealed the PRC's interpretive order to the New Mexico Supreme Court. However, while the matter was pending before the Court, the PRC issued an order withdrawing the interpretive ruling. Also, in April 2017, the commission rejected an additional rate case over the use of a future test year.

State law permits utilities to request PRC approval to reflect construction work in progress, or CWIP, in rate base. The Commission may allow such treatment if it finds "that a project's costs are reasonable." (Section updated 5/10/17)

Return on Equity

On Sept. 5, 2018, in the most recent electric rate case decision issued by the PRC, the commission authorized Southwestern Public Service Company a 9.1% ROE. On Dec. 20, 2017, PNM Resources subsidiary Public Service Company of New Mexico was authorized a 9.575% ROE following a settlement. In 2016, in, El Paso Electric was authorized a 9.48% ROE in a fully litigated proceeding.

In 2012, New Mexico Gas Company, or NMGC, was authorized a 10% ROE following a rate case settlement. The ultimate parent of NMGC is Emera. (Section updated 11/8/18)

Accounting

Public Service Company of New Mexico (PSNM) and El Paso Electric have established external trusts for funds collected from ratepayers for the future decommissioning of the Palo Verde (PV) 1 & 2 nuclear units. Neither PSNM's nor El Paso's PV 3 decommissioning costs may be recovered from ratepayers. PSNM and El Paso own 10.2% and 15.8% of PV, respectively.

In Southwestern Public Service's March 2014 rate decision, the PRC included in rate base the company's entire prepaid pension asset, indicating that the utility should earn a return on this asset in order to recover its cost of service. (Section updated 1/2/15)

Alternative Regulation

Through year-end 2007, Public Service Company of New Mexico (PSNM) was permitted to retain all revenues from off-system sales (OSS). With the implementation of the company's fuel and purchased power cost adjustment clause (FPPCAC) in 2008, all OSS revenues were required to be credited to the fuel clause balancing account. However, the PRC adopted a settlement on April 23, 2014, that provides for PSNM to retain 10% of OSS margins (and allocate 90% of OSS margins to ratepayers).

A renewable energy rider is in place for PSNM that includes a provision that requires the company to refund to ratepayers 100% of incremental earnings that are 50 basis points above its authorized equity return (10%).

The terms of a settlement for Southwestern Public Service adopted by the PRC in 2010 permits SWPS to continue to utilize 90% of the company's jurisdictional share of non-firm OSS margins to offset New Mexico-jurisdictional fuel costs.

Since 2004, El Paso Electric has been permitted to use an "indirect" hedge – El Paso is permitted to charge a fixed price for fuel and purchased power expenses for 10% of its sales in New Mexico.

An OSS margin-sharing provision is in place for EL Paso Electric through which the company flows 90% of the OSS margins to ratepayers through its FPPCAC. The OSS provision is to be in place through June 30, 2015. Prior to 2007, there was no OSS margin sharing in New Mexico; El Paso retained all margins from such sales. (Section updated 1/2/15)

Court Actions

PRC decisions may be appealed directly to the New Mexico Supreme Court. Judges are initially appointed by the governor or are elected; if appointed, they must receive voter approval to remain in office.

Two separate appeals of 2015 PRC orders for Public Service Company of New Mexico, or PSNM, and Southwestern Public Service rejecting the use of fully forecasted test years in rate cases had been appealed to the state Supreme Court. However, while these appeals were pending, on Dec. 9, 2015, the commission withdrew a test year ruling it had relied upon to reject the two rate case filings, effectively concluding the appeals.

On Oct. 27, 2016, PSNM appealed certain aspects of a Sept. 28, 2016 PRC base rate case decision for the company to the New Mexico Supreme Court. The appeal is ongoing. (Section updated 5/10/17)

Legislation

The New Mexico Legislature meets for 30 days in even-numbered years and for 60 days in odd-numbered years, beginning on the third Tuesday in January. Currently, there are 26 Democrats and 16 Republicans in the Senate, and 38 Democrats and 32 Republicans in the House of Representatives.

Legislation, Senate Bill 312, that would have increased the state's renewable portfolio standards such that renewable energy would have comprised 80% of each investor owned utility's total retail sales to New Mexico customers by 2040, was introduced, but ultimately not enacted in 2017. The 2017 legislative session adjourned on March 18. (Section updated 5/10/17)

Corporate Governance

Several mergers and acquisitions involving New Mexico utilities have been approved by the PRC in the last several years, and the Commission has imposed certain corporate governance conditions in the context of these cases.

In 2001, the PSC approved a settlement between Public Service Company of New Mexico (PSNM) and other parties, under which PSNM ultimately formed a holding company, PNM Resources. Conditions specified by the settlement included: PSNM may not pay dividends at a level that causes its debt rating to be below investment grade; the PRC will retain jurisdiction over any reciprocal loan agreement between PSNM and the holding company; the ratemaking impacts of any asset transfer approved in conjunction with the formation of the holding company are to be reserved for future rate proceedings; PSNM must obtain approval for purchases of capacity or energy from the non-utility subsidiaries of any of the utility holding companies; the PRC has jurisdiction to review the prudence of costs of wholesale power purchased by PSNM; PSNM must waive any claims of Securities and Exchange Commission or the Federal Energy Regulatory Commission preemption of PRC orders concerning cost allocation resulting from the creation of the holding company; and, the PRC will retain authority over the construction and siting of generation and transmission facilities.

In 2001, the PRC authorized El Paso Electric to form a holding company subject to similar terms and conditions adopted for PSNM. El Paso declined to proceed under the terms and conditions adopted by the PRC, and upon the company's request, the PRC rescinded the order. (Section updated 1/2/15)

Merger Activity

A merger transaction is to be approved unless the PRC finds that it is unlawful or inconsistent with the public interest. The PRC has identified four principal factors it must consider when reviewing a proposed merger or acquisition: (1) whether the transaction provides benefits to utility customers; (2) whether the PRC's jurisdiction will be preserved; (3) whether the quality of service will be diminished; and, (4) whether the transaction will result in the improper subsidization of non-utility activities.

In 1997, the Commission approved the merger of Southwestern Public Service, or SWPS, and Public Service of Colorado to form New Century Energies, or NCE. The merger closed in August 1997. SWPS' jurisdictional customers received an annual credit of $1.2 million for five years. The credit represented 50% of the non-fuel, net merger savings expected during the first five years of the merger.

In 2000, the PRC approved the proposed merger of New Century Energies and Northern States Power, or NSP, to form Xcel Energy. In approving the merger, the PRC directed SWPS to flow through to customers guaranteed net merger savings of $65,000 per month for 54 months--equal to $0.8 million annually or about $4 million over 54 months, with 66.3% of the projected net merger savings allocated to SWPS' New Mexico jurisdiction--actual savings in excess of this level was also to be flowed through. Certain corporate governance provisions were also adopted. Additionally, the PRC indicated that customers were to be held harmless from any financial and other negative impacts that may result from the merger. The cost of capital for operating subsidiary SWPS that is reflected in rates was not to be increased because of the merger, and SWPS was not permitted to seek recovery of any stranded costs related to the merger or attributable to NSP. The merger closed in August 2000.

In 2000, the PRC approved the acquisition of then Texas-New Mexico Power, or TNMP, parent TNP Enterprises by ST Acquisition Corp., subject to certain conditions proposed by the PRC Staff. The PRC required that covenants be included in TNP's debt, and that other measures be implemented to ensure that TNMP's service quality, rates, and operations were not affected by the transaction.

In 2005, the PRC approved PNM Resources' acquisition of TNP Enterprises, subject to conditions contained in a settlement reached by the parties. TNMP was required to implement a 15.8% rate reduction, phased in over three years. Merger savings of $7 million were allocated to Public Service Company of New Mexico, or PSNM, electric customers following the conclusion of a rate moratorium in January 2008, and PSNM gas customers received $4.3 million of rate credits. The transaction closed in mid-2005.

In 2000, PSNM and Western Resources, or WR, had announced an agreement under which PSNM was to acquire WR's electric utility operations. Following restrictive merger-related orders issued by the Kansas Corporation Commission, the proposal was ultimately terminated.

In 2008, the PRC approved PNM Resources' proposal to sell its gas business to Continental Energy Systems, or CES. The stipulation included several ring-fencing measures, including: target capital structures for both the purchased utility, renamed New Mexico Gas Company, or NMGC, and its then parent, CES; dividend restrictions for CES if the firm's equity ratio falls below 35%; a three-year rate freeze for NMGC from the date of closing; no financial obligations incurred by an NMGC affiliate that are secured by the assets of NMGC; neither NMGC, nor a substantial portion of its assets, could be sold for at least five years; minimum capital expenditures during the rate freeze for major projects or replacements; no recovery of acquisition costs, goodwill, transaction costs, or intangible assets resulting from the transaction; NMGC to maintain its corporate headquarters in Albuquerque so long as it is owned by Continental; and, in the event NMGC issues investment-grade debt, NMGC would not pay dividends that would cause its rating to fall below investment grade.

In 2014, the PRC approved TECO Energy's proposed acquisition of NMGC from CES. The transaction closed in September 2014. The PRC adopted a stipulation that included the following conditions: TECO agrees that there will be no future rate impact associated with the acquisition premium; NMGC will not file for an increase in rates to be effective prior to Dec. 31, 2017; NMGC is to implement a $2 million distribution rate reduction beginning one month after closing, with an additional $2 million reduction to be implemented one year later; TECO is required to maintain a post-closing equity ratio for NMGC of at least 50%, until a final order is issued in NMGC's next rate case; NMGC will not request an equity ratio in its next base rate proceeding in excess of 54%; NMGC will not, without PRC approval, pay dividends in excess of net income on a quarterly basis; NMGC will not pay dividends at any time its credit metrics are below investment grade; and, TECO would not sell its interest in NMGC for at least 10 years after closing.

In June 2016, the PRC adopted a settlement, thereby approving Emera's proposed acquisition of NMGC parent TECO Energy. The transaction closed on July 1, 2016. Per the terms of the adopted settlement, NMGC is to: refrain from filing for a rate increase until at least Dec. 31, 2017, and is to use a historic test year in its next rate case filing; refrain from seeking a capital structure containing an equity ratio larger than 54% in its next rate case; maintain a capital structure containing an equity ratio of 50% or greater until the conclusion of NMGC's next rate case; provide a $4 million annual rate credit through June 30, 2018; pursue several shareholder-funded economic development activities in New Mexico, including a $5 million pipeline enlargement project to export gas to Mexico, a matched $10 million, five-year fund aimed at extending gas infrastructure to unserved and underserved communities, and a $5 million contribution to be made within five years of the close of the deal to be allocated to general projects; contribute $0.8 million annually to charities or to fund economic development/business development activities for three years after the close of the transaction; continue to make investments, at a rolling three-year average level, to ensure system safety and reliability until NMGC's next rate case decision is issued; refrain from paying dividends that exceed its quarterly net income, although the company may "rollover under-utilized dividending capacity in any quarter to a subsequent period"; and, be prohibited from paying dividends if its credit ratings fall below investment grade. In addition, the adopted settlement requires: Emera and NMGC agree "to waive future claims of federal preemption of [PRC] decisions regarding rate setting and cost allocations"; Emera to establish a separate subsidiary board of directors to oversee NMGC that would include local business and community leaders; and, Emera to refrain from selling NMGC, or affiliate New Mexico Gas Intermediate, for 10 years following the close of the deal. (Section updated 5/4/18)

Electric Regulatory Reform/Industry Restructuring

The state's initial restructuring law, Senate Bill (S.B.) 428, enacted in 1999, called for retail competition to commence in 2002; however, S.B. 718 was enacted in 2003 repealing retail access implementation, and allowing the utilities to recover any costs incurred to comply with S.B. 428. The bill retained a provision that permits a public utility "to have an interest in a generating plant that is not intended to provide service to retail customers and the cost of which is not included in retail rates and which business activities shall not be subject to regulation by the [PRC]."

As per the terms of a stipulation for Public Service Company of New Mexico (PSNM) that was approved by the PRC in 2003, PSNM was to be the sole retail provider of generation in the company's service territory through at least Jan. 1, 2010. (The company continues to be the sole retail provider in its territory.) Regarding merchant power, PNM Resources shareholders were permitted to retain the revenues from merchant generation expansion, and the company would continue to jointly dispatch both its regulated and unregulated generating facilities at least through 2015. The signatories to the stipulation agreed to support legislation to repeal the state's restructuring statute, and later that year, as noted above, S.B. 718 was enacted. It should be noted that PSNM no longer owns merchant generation, with the exception of its share of Palo Verde 3. (Section updated 1/2/15)

Gas Regulatory Reform/Industry Restructuring

Gas service in New Mexico is unbundled for large volume customers. New Mexico Gas Company (NMGC) charges a "standby" rate for transportation-only customers who wish to retain the right to purchase gas from the local distribution company; NMGC is not obligated to provide gas supply to transportation-only customers who do not purchase standby service. In the late-1990s, the PRC approved an interim "Customer Choice Program" for Public Service Company New Mexico (NMGC's predecessor) that included rule changes, e.g., eliminating customer participation fees in order to facilitate small-volume customer transportation. The program was initially limited to customers using less than 10,000 therms per year. The PRC later expanded the program to include residential and small commercial customers using more than 10,000 therms per year. (Section updated 1/2/15)

Adjustment Clauses

Commission rules provide for automatic fuel adjustment clauses; the fuel and purchased power cost adjustment clause, or FPPCAC, for an electric utility is calculated monthly, but a variance from monthly reporting may be sought. The FPPAC includes a balancing account in which there is approximately a two-month collection lag. A utility is required to reapply for continuation of an FPPCAC every four years, at which time a comprehensive review of the clause is undertaken.

In 2008, the PRC authorized Public Service Company of New Mexico, or PSNM, to establish an emergency FPPCAC. The clause contained several conditions, including that the recoverable costs were subject to a prudence review. PSNM's FPPCAC had been eliminated in 1994, following a stipulation. In 2009, the PRC adopted a rate case settlement that included the reinstatement of the company's FPPCAC on a permanent basis. The fuel factor is adjusted annually. Additionally, the approved settlement contained an SO2 rider through which customers are credited with their share of revenues from allowance sales.

El Paso Electric may seek approval to adjust its FPPCAC if the company experiences an over- or under-recovery balance of at least $2 million of fuel and purchase power expenses as of December 31 and June 30 of each year.

Southwestern Public Service, or SWPS, uses an FPPCAC under which it may petition for a change in the fuel factor if the over/under-recovery balance reaches $5 million. In SWPS' March 2014 rate case decision, the PRC established a renewables cost recovery rider that is to be adjusted and trued up on an annual basis.

PSNM has riders in place that are designed to recover cost associated with undergrounding distribution projects in Rio Rancho and Albuquerque.

Energy efficiency program riders are in place for EPE, New Mexico Gas Company, or NMGC, PSNM, and SWPS.

A renewable energy rider is in place for PSNM that reflects the costs of compliance with the state's renewable energy procurement requirements, and provides for the deferral of renewable energy costs that exceed certain thresholds. The rider also includes an incentive provision (see the Alternative Regulation section). SWPS also has a renewable energy rider in place.

Per a Sept. 5, 2018 PRC decision, SWPS is to implement a rider related to federal tax reform. However, the company is appealing that aspect of the commission's decision.

Purchased gas adjustment clauses, or PGACs, are utilized. Changes in the PGAC are made without hearings if a proposed increase is less than 10% of the previous factor. An annual reconciliation audit is required. Monthly over- and under-recoveries of gas costs are reflected through a monthly balancing adjustment to the PGAC. Continued use of the PGAC must be justified every four years. The cost of gas reflected in the PGAC is based upon market projections and averaged/levelized over a pre-determined period. NMGC uses hedging instruments to mitigate the impact of spikes in the cost of gas, and the financing cost of hedging contracts are recovered through the PGAC.

Despite a 2008 directive legislative directive that required the removal of disincentives to a utility's implementation of energy efficiency programs, PSNM has tried, and failed, several times in recent years to obtain PRC approval to implement a revenue decoupling mechanism. In a 2007 gas rate decision that predated the directive, the commission rejected the company's proposed decoupling mechanism, stating that the proposal was too broad. The PRC concluded that the mechanism would make PSNM whole for past conservation efforts of consumers and was, therefore, fatally flawed. The PRC stated that it would not consider a decoupling mechanism of this type in any case. As per an electric rate case stipulation adopted by the PRC in 2011, PSNM was required to withdraw its request for a decoupling mechanism. The PRC also rejected a decoupling proposal by the company as part of a Sept. 28, 2016 decision in a recent PSNM rate case.

In a separate, but related issue, in 2011, the State Supreme Court overturned a 2010 PRC order in which the Commission had amended its rules to permit each electric utility to recover a $0.01 "adder" for each KWH saved and $10 for each KW reduced due to approved energy efficiency programs. After two years, the adder was to be reduced to $0.005 per KWH saved. The Supreme Court, however, determined that the PRC's adoption of the adder was "arbitrary and unlawful."

Also in 2011, in a PRC rate case decision for PSNM in which the commission significantly modified a proposed settlement, the PRC eliminated provisions that would have allowed the company to implement a temporary capital additions rider that was to be in effect during an agreed-upon rate case moratorium. (Section updated 9/12/18)

Integrated Resource Planning

The state's electric integrated resource planning (IRP) rules require each utility to file, every three years, a 20-year IRP plan with the PRC. The plan is to include: a description of existing supply- and demand-side resources; a current load forecast for each year of the 20-year planning period; a determination of the most cost-effective resource options; and, an action plan covering the first four years of the planning period. Additionally, each utility must disclose its existing and under-construction transmission facilities of at least 115 KV, and any power transfer capability limitations on its system. Also, the utility is required to compare the annual forecast of coincident peak demand and energy sales to the actual coincident peak and energy sales for the four years preceding the year in which the plan under consideration is filed. In any future proceeding in which a utility seeks a certificate to construct a facility, the company must show that the requested resource is consistent with the accepted IRP plan.

The state's gas IRP rules require each utility to file, every four years, a four-to-10-year IRP plan with the PRC. Each plan must contain: a current load forecast; a description of existing resources; a summary of foreseeable resource needs for the planning period; and, anticipated resources to be added during the planning period. If the PRC has not acted within 45 days after the filing of an IRP, the plan is deemed approved. As with the electric IRPs, any gas company requesting a certificate to construct a facility must show that the proposal is consistent with the approved IRP plan.

In 2013, legislation was enacted that revised the state's standards with respect to energy efficiency and load management (EE/LM) resources. The law requires electric utilities to acquire "cost-effective and achievable" EE/LM resources, with the demand savings from such resources to be 5% of 2005 total retail KWH sales in calendar-year 2014, and 8% (down from 10%) of 2005 sales in 2020. These savings levels are to come from EE/LM programs implemented beginning in 2007. If a utility establishes that it cannot achieve these minimum standards, the PRC would be permitted to establish lower requirements for that utility. (Section updated 1/2/15)

Renewable Energy

New Mexico's renewable portfolio standard, or RPS, had required at least 15% of each of the state's major electric utilities' total retail load be served by renewable resources by 2015, with the RPS requirement to increasing to 20% by 2020. Legislation enacted on March 22, 2019, increased the RPS such that renewable energy is to comprise the following percentages of the utilities' total retail sales: 40% by 2025; 50% by 2030; 80% by 2040; and 100% by 2045.

Compliance with the above noted RPS targets permits the utilities to retain zero carbon resources in their generation portfolios until Dec. 31, 2047. Zero carbon resources, which would include nuclear power plants, are defined in the legislation as generation assets that do not produce CO_2 emissions, "or that reduces methane emitted into the atmosphere in an amount equal to no less than one-tenth of the tons of [CO_2] emitted into the atmosphere, as a result of electricity production."

Renewables are defined renewable energy resources as solar, wind, geothermal, and certain hydropower facilities, as well as fuel cells that are not fossil fuel based, and biomass resources, such as agriculture or animal waste, small diameter timber, etc. Senate Bill 489 amended the definition of renewable energy resource to now include landfill gas and waste biogas, and alters the biomass resource definition to generally exclude resources that are not sustainable and/or produce carbon emissions. The law states that the public utilities should be able to recover the costs incurred pursuant to a PRC-approved plan to procure or generate energy from renewable resources used to meet the requirements of the law. The law also states that the utilities should not be required to acquire energy generated from renewable resources that could result in costs that are "above a reasonable threshold." See below regarding the PRC's Notice of Proposed Rulemaking, or NOPR, regarding this provision of the law. In addition, a 2007 law created a regional energy transmission authority to assist in the development of renewable resources.

PRC rules require that, in developing a renewable energy portfolio, utilities consider the potential for environmental and economic benefits to New Mexico. Renewable energy resources that were part of the utility's electric energy supply portfolio as of July 1, 2004, are to be counted in determining compliance with this rule. However, renewable energy sold to customers at "premium" prices will not be counted in determining compliance. Preference is to be given to renewable energy generated in New Mexico. Additionally, each utility is to meet its renewable requirements using a diverse portfolio of resources, taking into consideration the overall reliability, availability, dispatch flexibility and cost of the various renewable resources. The PRC established specific resource diversity requirements in the rules, requiring that at least 30% of RPS be supplied from wind resources, 20% from solar resources, 5% from other non-wind/non-solar resources, and 1.5% from distributed generation resources, which increased to 3% in 2015.

In 2011, the PRC issued a NOPR to establish "a standardized methodology for calculating the cost of renewable energy for purposes of applying the Reasonable Cost Threshold, or RCT, and for determining whether and how that cost should be used for ratemaking purposes." The RCT is defined as the cost established by the PRC above which a public utility shall not be required to add renewable energy to its electric energy supply portfolio pursuant to the renewable portfolio standard. In 2012, the PRC issued an order that set the RCT at 3% of "all customers' aggregated overall annual electric charges." (Section updated 3/26/19)

Emissions Requirements

In 2013, PNM Resources, Public Service Company of New Mexico, or PSNM, the New Mexico Environment Department, or NMED, and the U.S. EPA announced an agreement that would enable the coal-fired San Juan generating station, or SJGS, which is 46%-owned by PSNM, to comply with the federal visibility rules of the Clean Air Act. In 2011, the EPA had issued a ruling requiring the installation of selective catalytic reduction, or SCR, technology on all four units of the SJGS station by September 2016, in lieu of a less expensive resolution required by the State of New Mexico. PSNM estimated that the installation of SCR at SJGS would cost approximately $824 million to $910 million, versus the State-proposed resolution that would cost roughly $82 million. Under the 2013 agreement, SJGS Units 2 and 3 would be retired by the end of 2017, and selective non-catalytic reduction, or SNCR, technology would be installed on SJGS Units 1 and 4 by early 2016. The plan calls for the construction of a natural gas plant and peaking facilities to partially replace the capacity from the retired coal units, but such plans would be finalized independently from the agreement. Additionally, the company indicated that it would evaluate the possibility of including its share unregulated of the Palo Verde 3, or PV3, nuclear plant to rate base as a source of replacement power. The NMED issued a revised implementation plan, which has since been approved by the New Mexico Environmental Improvement Board and the EPA.

On Dec. 22, 2015, the PRC adopted settlements filed in a state-level proceeding associated with SJGS's emissions authorizing PSNM to acquire, effective Jan. 1, 2018, 132 MW of additional generating capacity from the SJGS unit 4 to serve its retail ratepayers, and to acquire a separate, additional 65 MW of capacity from SJGS Unit 4 that is to be treated as a merchant plant. In addition, the company is to include in rate base, effective Jan. 1, 2018, its 134-MW share of the PV3 facility. Also, PSNM is to petition the PRC to reflect in rates the costs associated with installing SNCR equipment at SJGS units 1 and 4. The approved settlement also provides for PSNM to retire SJGS units 2 and 3 effective Dec. 31, 2017. (Section updated 5/10/17)

Rate Structure

The PRC has approved several special rates for Public Service Company of New Mexico, or PSNM, designed to retain customer load or attract new load, including economic development rates, or EDRs. PSNM offers an Experimental Incremental Interruptible Power Rate for incremental on-peak loads. Individual EDR contracts do not require PRC approval if the tariff is already in place. El Paso Electric has made limited use of EDRs.

As part of a Sept. 28, 2016 rate case decision for PSNM, the PRC permitted the company to implement, for large use customers, three part rates consisting of a customer charge, a demand charge and volumetric charge. (Section updated 5/10/17)

S&P Global
Market Intelligence

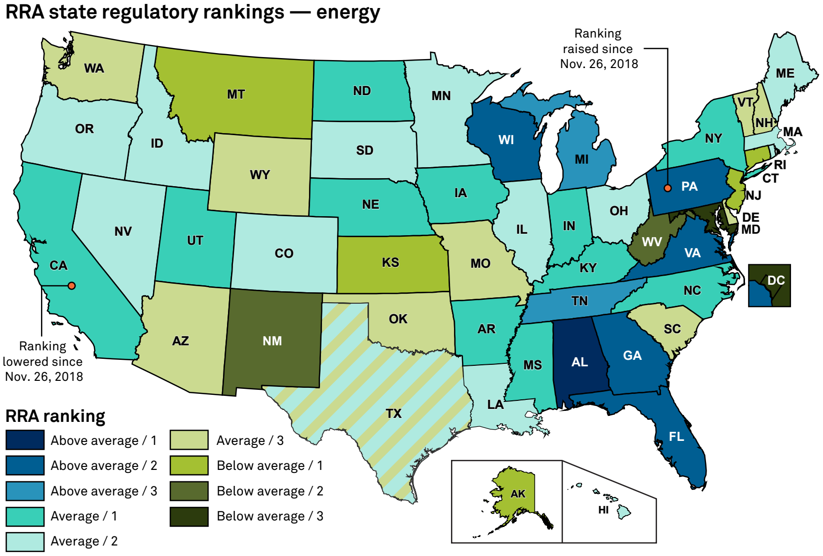
February 8, 2019
spglobal.com/marketintelligence

RRA Regulatory Focus
State Regulatory Evaluations

Assessments of regulatory climates for energy utilities

Regulatory Research Associates, or RRA, evaluates the regulatory climate for energy utilities in each of the jurisdictions within the 50 states and the District of Columbia, a total of 53 jurisdictions, on an ongoing basis. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by each jurisdiction's electric and gas utilities.

RRA state regulatory rankings — energy



As of Feb. 6, 2019.
Texas PUC is ranked Average/3 and the Texas RRC is Average/2.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Each evaluation is based upon consideration of the numerous factors affecting the regulatory process in the state and may be adjusted as events occur that cause RRA to modify its view of the regulatory risk accruing to the ownership of utility securities in that individual jurisdiction.

RRA also reviews evaluations when updating Commission Profiles and when publishing this quarterly comparative report. The issues considered are discussed in RRA Research Notes, Commission Profiles, Rate Case Final Reports and Topical Special Reports. RRA also considers information obtained from contacts with commission, company and government personnel in the course of its research. The final evaluation is an assessment of the probable level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative and court actions.

RRA state regulatory evaluations
Energy

Above Average 1	Average 1	Below Average 1
Alabama	Arkansas	Alaska
	California	Connecticut
	Indiana	Kansas
	Iowa	Montana
	Kentucky	New Jersey
	Mississippi	
	Nebraska	
	New York	
	North Carolina	
	North Dakota	
	Utah	
Above Average 2	**Average 2**	**Below Average 2**
Georgia	Colorado	New Mexico
Florida	Hawaii	West Virginia
Pennsylvania	Idaho	
Virginia	Illinois	
Wisconsin	Louisiana—NOCC	
	Louisiana—PSC	
	Maine	
	Massachusetts	
	Minnesota	
	Nevada	
	Ohio	
	Oregon	
	Texas—RRC	
	Rhode Island	
	South Dakota	
Above Average 3	**Average 3**	**Below Average 3**
Michigan	Arizona	District of Columbia
Tennessee	Delaware	Maryland
	Missouri	
	New Hampshire	
	Oklahoma	
	South Carolina	
	Texas—PUC	
	Vermont	
	Washington	
	Wyoming	

As of Feb. 6, 2019.
NOCC = New Orleans City Council; PSC = Public Service Commission;
PUC = Public Utility Commission; RRC = Railroad Commission
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence.

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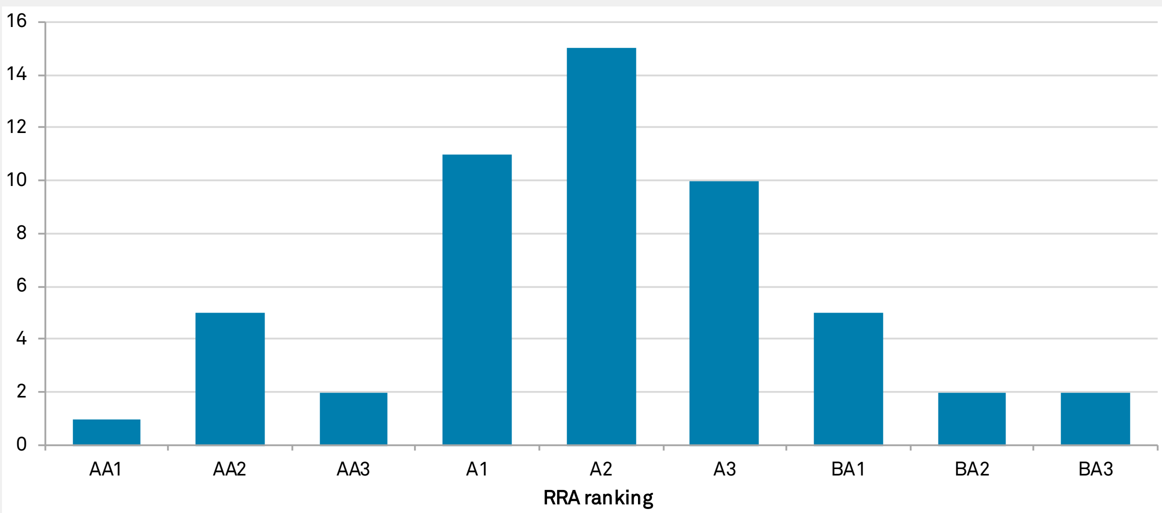
An Above Average designation indicates that, in RRA's view, the regulatory climate in the jurisdiction is relatively more constructive than average, representing lower risk for investors that hold or are considering acquiring the securities issued by the utilities operating in that jurisdiction.

At the opposite end of the spectrum, a Below Average ranking would indicate a less constructive, higher-risk regulatory climate from an investor viewpoint.

A rating in the Average category would imply a relatively balanced approach on the part of the governor, the legislature, the courts and the commission when it comes to adopting policies that impact investor and consumer interests.

Within the three principal rating categories, the designations 1, 2 and 3 indicate relative position, with a 1 implying a more constructive relative ranking within the category, a 2 indicating a mid-range ranking within the category and a 3 indicating a less constructive ranking within the category.

State regulatory rankings distribution*



As of Feb. 6, 2019.
* Graph is based on rankings of regulatory climate for energy utilities only.
AA= Above Average; A=Average; BA=Below Average
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

RRA attempts to maintain a "normal distribution" of the rankings, with the majority of the states classified in one of the three Average categories. The remaining states are the split relatively evenly between the Above Average and Below Average classifications, as seen in the accompanying chart that depicts the current distribution of the rankings. For a more in-depth discussion of the factors RRA reviews as part of its ratings process, see the Overview of RRA rankings process section that begins on page 6.

Rankings changes

Since the previous "State Regulatory Evaluations" report was published on Nov. 26, 2018, at which time RRA has made one ranking change — Jan. 23, 2019, RRA lowered the ranking of California regulation to Average/1 from Below Average/3 in light of the then-expected bankruptcy filing by PG&E Corp., parent of Pacific Gas and Electric Co., or PG&E. The company tendered the filing on Jan. 29. The company decided to file for Chapter 11 bankruptcy protection in light of tens of billions of dollars in potential liabilities related to the 2017 and 2018 Northern California wildfires. While 2018 legislation appears to provide some relief for PG&E with respect to liabilities for wildfires that occurred in 2017, the lack of regulatory or legislative protections against subsequent wildfire liabilities caused by the application of inverse condemnation to investor-owned utilities prompted RRA to reassess its view of the regulatory construct in the state. Inverse condemnation exposes all of the California utilities, not just PG&E, to liabilities from wildfires, regardless of whether they were negligent, as long as their equipment was involved in the incident. These considerations aside, the regulatory climate in California has been relatively constructive in recent years, as equity return authorizations for the state's major energy utilities are established utilizing cost-of-capital adjustment mechanisms and recent authorizations have been above the industry averages when established. Full electric and gas revenue decoupling mechanisms are in place, and certain segments of utility operations are subject to performance-based ratemaking mechanisms. For additional detail, refer to the California Commission Profile.

In conjunction with the release of this update, RRA is raising the ranking of Pennsylvania to Above Average/2 from Above Average/3. The climate in the state has been relatively constructive and pro-business for some time. State policy allows the use of fully forecast test periods and year-end rate base valuations. In addition, virtually all of the energy utilities in the state utilize distribution system improvement charges, or DSICs, that allow them to reflect incremental investment in rates on a quarterly basis. These policies reduce regulatory lag even though there are certain limitations on the adjustments. Since most rate cases are resolved via black box settlements that are silent with respect to the underlying ROE, the commission establishes the ROE to be used in the DSICs on a generic basis. In recent quarters the PUC has raised the ROEs authorized in these generic proceedings fairly regularly, and as a result, the authorized ROEs are above the average ROEs authorized in base rate case proceedings, as observed by RRA. In the most recent determination, the Pennsylvania Public Utility Commission approved a generic ROE of 9.65% for electric utilities and 10.15% for gas utilities. In addition, in the only fully litigated base rate case in more than five years, the PUC approved a 9.85% ROE for an electric utility. According to data gathered by RRA, the average ROE authorized in electric distribution-only rate cases decided during 2018 was 9.38% while the average for gas local distribution companies was 9.59%. For additional information on regulation in Pennsylvania, refer to the Pennsylvania Commission Profile.

RRA state regulatory evaluations

State-by-state listing — Energy

State	Ranking	State	Ranking	State	Ranking
Alabama	Above Average / 1	Louisiana—NOCC	Average /2	Ohio	Average / 2
Alaska	Below Average / 1	Louisiana—PSC	Average / 2	Oklahoma	Average / 3
Arizona	Average / 3	Maine	Average / 2	Oregon	Average / 2
Arkansas	Average / 1	Maryland	Below Average / 3	Pennsylvania*	Above Average / 2
California**	Average /1	Massachusetts	Average / 2	Rhode Island	Average / 2
Colorado	Average / 2	Michigan	Above Average / 3	South Carolina	Average / 3
Connecticut	Below Average /1	Minnesota	Average / 2	South Dakota	Average / 2
Delaware	Average / 3	Mississippi	Average / 1	Tennessee	Above Average / 3
District of Columbia	Below Average /2	Missouri	Average / 3	Texas—PUC	Average /3
Florida	Above Average / 2	Montana	Below Average / 1	Texas—RRC	Average / 2
Georgia	Above Average /2	Nebraska	Average / 1	Utah	Average / 1
Hawaii	Average / 2	Nevada	Average / 2	Vermont	Average / 3
Idaho	Average / 2	New Hampshire	Average / 3	Virginia	Above Average / 2
Illinois	Average / 2	New Jersey	Below Average/ 1	Washington	Average / 3
Indiana	Average / 1	New Mexico	Below Average /2	West Virginia	Below Average / 2
Iowa	Average /1	New York	Average /1	Wisconsin	Above Average / 2
Kansas	Below Average/1	North Carolina	Average / 1	Wyoming	Average / 3
Kentucky	Average / 1	North Dakota	Average / 1		

As of Feb. 6, 2019.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility Commission; RRC = Railroad Commission
* Ranking lowered since Nov. 26, 2018.
** Ranking lowered since Nov. 26, 2018.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence.

States to watch

It goes without saying that RRA will continue to monitor the PG&E bankruptcy proceeding in California for both positive and negative indicators, but that will be a long, drawn-out process, with a resolution well into the future.

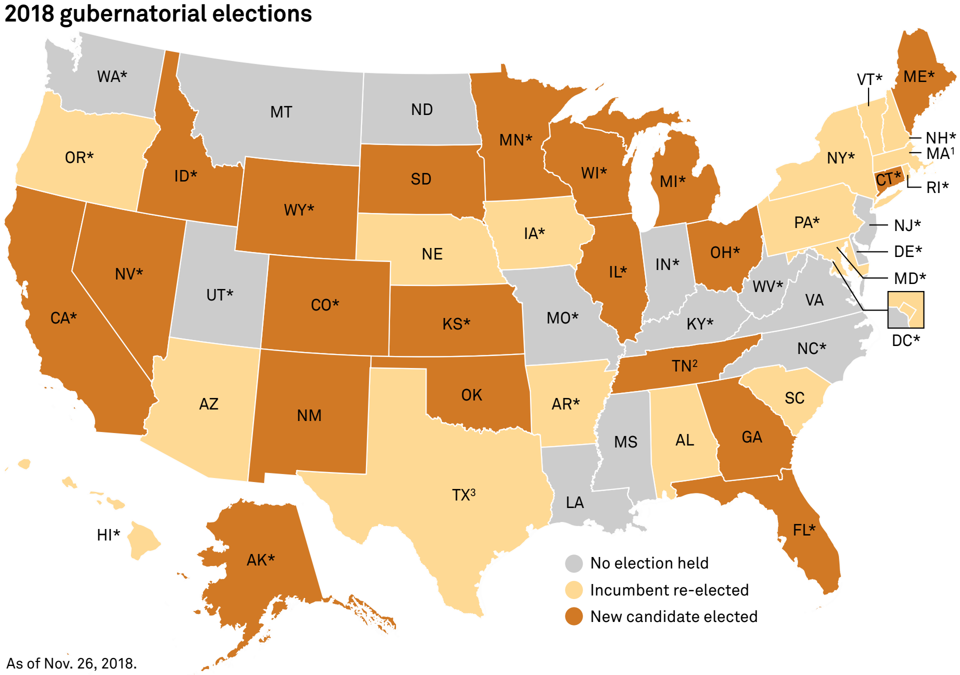
Several other jurisdictions are also in the midst of proceedings, the outcome of which have the potential to alter RRA's view of the regulatory climate in the respective jurisdictions.

In South Carolina, the ongoing controversy surrounding SCE&G's Summer nuclear plant expansion, which led to two recent downgrades of that jurisdiction, is ongoing. However, concerns that the situation could negatively impact the proposed acquisition of SCE&G parent SCANA by Dominion Energy are no longer a consideration as the deal closed on Jan. 2, 2019.

Similarly, RRA is continuing to monitor the ongoing situation in Georgia, with respect to Southern Co. subsidiary Georgia Power Co.'s endeavors to achieve rate recognition of its nuclear expansion project at Vogtle units 3 and 4. The commission conducts a semiannual review of the project's costs and determines the prudence/eligibility for recovery of the investment. A settlement was recently filed in the 19th such review, and Georgia Power is expected to file a base rate case in mid-2019.

In Virginia, on the heels of the enactment in 2018 of comprehensive electric regulatory legislation, which among other things extended the time frame for earnings reviews of the state's largest utilities to three years from two, legislation has been introduced in the 2019 session that would revert to the two-year review process and would remove some of the constructive provisions of existing framework. It is early in the session as yet, and it remains to be seen whether the bill will advance. Recent allegations against Gov. Ralph Northam and the potential that he will leave office before the end of his terms also bears watching.

2018 gubernatorial elections



As of Nov. 26, 2018.
* Commissioners are selected by the governor, or, in the case of D.C., the mayor.
1 Commissioners are appointed by the secretary of the Office of Energy and Environment Affairs, with the governor's approval.
2 Members of the Tennessee PUC are selected by the governor, the speaker of the House and the speaker of the Senate.
3 Members of the PUC of Texas are appointed by the governor; members of the Railroad Commission of Texas are elected.
Map credit: Junaid Rehman
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence.

In Pennsylvania, Gov. Tom Wolf issued an Executive Order in January establishing a statewide goal to reduce greenhouse gas emissions by 80% by 2050, and Feb. 4, a bipartisan group of lawmakers in the House of Representatives and Senate issued a memo seeking more sponsors for a proposal to provide economic support to "at-risk" nuclear plants. A bill has not yet been introduced. In addition, it appears that Ohio may consider a similar measure.

Proceedings regarding reforming the electric delivery system and/or regulatory framework are underway in Hawaii, Iowa, Maryland, New Hampshire, New Mexico, Ohio, Oklahoma, Oregon and Pennsylvania.

In Iowa, legislation was enacted in May 2018 directing the Iowa Utilities Board to develop rulings with respect to certain aspects of the traditional regulatory process, such as test year and rate base valuation. A proceeding has not yet been launched, and it remains to be seen whether the new rules will incorporate major changes to existing practices.

In addition, in many states, proceedings are ongoing with respect to the impacts of the federal tax changes enacted in December 2017 that lowered the corporate federal income tax rate to 21% from 35%. RRA is monitoring these proceedings and will be on the lookout for jurisdictions that take an innovative approach to this challenge.

General elections were held on Nov. 6, 2018, and the results could bring about changes in policy and the make-up of commissions in certain states — 36 governors, the mayor of the District of Columbia and 19 utility commissioner positions across 11 states were up for grabs.

In 20 of the 36 gubernatorial races a new governor was elected, and in 15 of the jurisdictions in which there is a new governor, it is the governor that appoints members to the state utility regulatory agency. Many of the newly elected governors are emphasizing climate change in their first days in office, and it remains to be seen what their policies will mean for utilities.

Similarly, legislative sessions are in full swing across the country and consistent with prior years, hot topics are renewables expansion, electric vehicles, emissions, carbon pricing and the future of the nuclear industry.

With the completion over the last several weeks of the Dominion Energy Inc./SCANA Corp. merger, the CenterPoint Energy Inc./Vectren Corp. merger and the NextEra Energy Inc./Gulf Power merger, as well as the demise of HydroOne's proposed acquisition of Avista Corp., things are relatively quiet on the merger front, but a couple of utility-related deals bear watching.

In Texas, after a series of complex transactions ended with Sempra Energy Inc. acquiring Oncor Electric Delivery Co. LLC in late-October, Sempra announced a plan under which Oncor would acquire transmission owner InfraREIT Inc. and Sempra would acquire a 50% stake in Sharyland Utilities LP from Hunt Consolidated. The transactions are subject to review by the Texas Public Utility Commission, and that proceeding is in the early stages.

Also in October 2018, Aqua America Inc. a multistate water utility holding company announced that it had reached an agreement to acquire Pennsylvania gas utility Peoples Natural Gas and its subsidiaries. The transaction is subject to review by the Pennsylvania Public Utility Commission, and that proceeding has just begun.

State Regulatory Reviews issued since prior report

Since the prior quarterly evaluations report was published on Nov. 26, 2018, RRA has issued State Regulatory Reviews affirming the rankings of several jurisdictions.

In a Maryland Regulatory Review published on Dec. 10, 2018, RRA maintained the Below Average/3 ranking of that jurisdiction, finding that the regulatory climate in that jurisdiction continues to be restrictive from an investor viewpoint.

In a North Carolina Regulatory Review issued on Dec. 11, 2018, RRA affirmed the Average/1 ranking of the state, noting that regulation there is overall somewhat constructive from an investor viewpoint.

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Market Intelligence

State Regulatory Evaluations

In a Dec. 20, 2018 Alaska Regulatory Review, RRA noted that the climate in the state continues to be somewhat restrictive from an investor viewpoint and maintained the Average/3 ranking of that jurisdiction.

In a Missouri Regulatory Review issued on Jan. 10, 2019, RRA affirmed its Average/3 ranking of the state. RRA had raised the ranking of this state in mid-2018 following enactment of legislation designed to reduce regulatory lag. Even so, the jurisdiction remains somewhat restrictive from an investor viewpoint.

In a Jan. 14, 2019 Arkansas Regulatory Review, RRA found that regulatory climate in the state continues to be somewhat constructive from an investor standpoint and maintained the Average/1 ranking of that jurisdiction.

Please note – RRA State Regulatory Reviews are issued periodically and are static in nature, but the information provided in these reviews is updated on a real-time basis in RRA's Commission Profiles.

RRA state regulatory evaluations — Energy

Above Average/1	Above Average/2	Above Average/3	Average/1	Average/2	Average/3	Below Average/1	Below Average/2	Below Average/3
Alabama	Georgia	Michigan	Arkansas	Colorado	Arizona	Alaska	New Mexico	District of Columbia
	Florida	Tennessee	California	Hawaii	Delaware	Connecticut	West Virginia	Maryland
	Pennsylvania		Indiana	Idaho	Missouri	Kansas		
	Virginia		Iowa	Illinois	New Hampshire	Montana		
	Wisconsin		Kentucky	Louisiana—NOCC	Oklahoma	New Jersey		
			Mississippi	Louisiana—PSC	South Carolina			
			Nebraska	Maine	Texas—PUC			
			New York	Massachusetts	Vermont			
			North Carolina	Minnesota	Washington			
			North Dakota	Nevada	Wyoming			
			Utah	Ohio				
				Oregon				
				Texas—RRC				
				Rhode Island				
				South Dakota				

As of Feb. 6, 2019.
NOCC=New Orleans City Council; PSC = Public Service Commission; PUC == Public Utility Commission; RRC = Railroad Commission
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence.

For a complete listing of RRA's in-depth reports, see the Energy Research Library.

Overview of RRA rankings process

RRA maintains three principal rating categories, Above Average, Average and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less constructive, higher-risk regulatory climate. Within the three principal rating categories, the numbers 1, 2 and 3 indicate relative position. The designation 1 indicates a stronger or more constructive rating from an investor viewpoint; 2, a mid-range rating; and 3, a less constructive rating within each higher-level category. Hence, if you were to assign numeric values to each of the nine resulting categories, with a "1" being the most constructive from an investor viewpoint and a "9" being the least constructive from an investor viewpoint, then Above Average/1 would be a "1" and Below Average/3 would be a "9."

The rankings are subjective and are intended to be comparative in nature. RRA endeavors to maintain an approximate normal distribution with an approximately equal number of rankings above and below the average. The variables that RRA considers in determining each state's ranking are largely the broad issues addressed in our State Regulatory Reviews/Commission Profiles and those that arise in the context of rate cases and are discussed in RRA Rate Case Final Reports.

The rankings not only reflect the decisions rendered by the state regulatory commission, but also take into account the impact of the actions taken by the governor, the legislature, the courts and the consumer advocacy groups. The policies examined pertain largely to rate cases and the ratemaking process, but issues such as industry restructuring, corporate governance and approach to proposed mergers are also considered.

The rankings are designed to reflect the interests of both equity and fixed-income investors across more than 30 individual metrics. The individual scores are assigned based on the covering analysts' subjective judgement. The scores are then aggregated to create a single score for each state, with certain categories weighted more heavily than others.

The states are then ranked from lowest to highest and distributed among the nine categories to create an approximate normal distribution. This distribution is then reviewed by the team as a whole, and individual state rankings may be adjusted based on the covering analysts' recommendations, subject to review by a designated panel of senior analysts.

The summaries below provide an overview of these variables and how each can impact a given regulatory environment.

Governor/Mayor

The impact the governor, or in the District of Columbia the mayor, may vary depending largely on the individual; the issue of elected versus appointed commissioners is evaluated separately.

RRA takes no view on whether Republican governors or Democratic governors are more or less constructive. However, attributes of the governor or the gubernatorial election process that can move the needle here are: whether energy issues were a topic of debate in recent elections and what the tone/topic of the debate was; and whether the governor seeks to involve himself or herself in the regulatory process, and what type of influence the governor is seeking to exert.

Commissioner selection process/membership

RRA looks at how commissioners are selected in each state. All else being equal, RRA attributes a greater level of investor risk to states in which commissioners are elected rather than appointed. Generally, energy regulatory issues are less politicized when they are not subject to debate in the context of an election.

Realistically, a commissioner candidate who indicates sympathy for utilities and appears to be amenable to rate increases is not likely to be popular with the voting public. In addition, there might not be a specific experience required to run for commissioner; so, a newly elected candidate may have a steeper learning curve with respect to utility regulatory and financial issues, which could make discerning what decisions that individual might make more difficult and could increase uncertainty.

However, there have been some notable instances in which energy issues in appointed-commission states became gubernatorial/senatorial election issues, with detrimental consequences for the utilities, e.g., Illinois, Florida and Maryland, all of which were downgraded by RRA at the time in order to reflect the risk associated with increased politicization of the regulatory process.

In addition, RRA looks at the commissioners themselves and their backgrounds. Experience in economics and finance and/or energy issues is generally seen as a positive sign. Previous employment by the commission or a consumer advocacy group is sometimes viewed as a negative indicator. In some instances, new commissioners have very little experience or exposure to utility issues, and in some respects, these individuals represent the highest level of risk, simply because there is no way to foresee what they will do or how long it will take them to "get up to speed."

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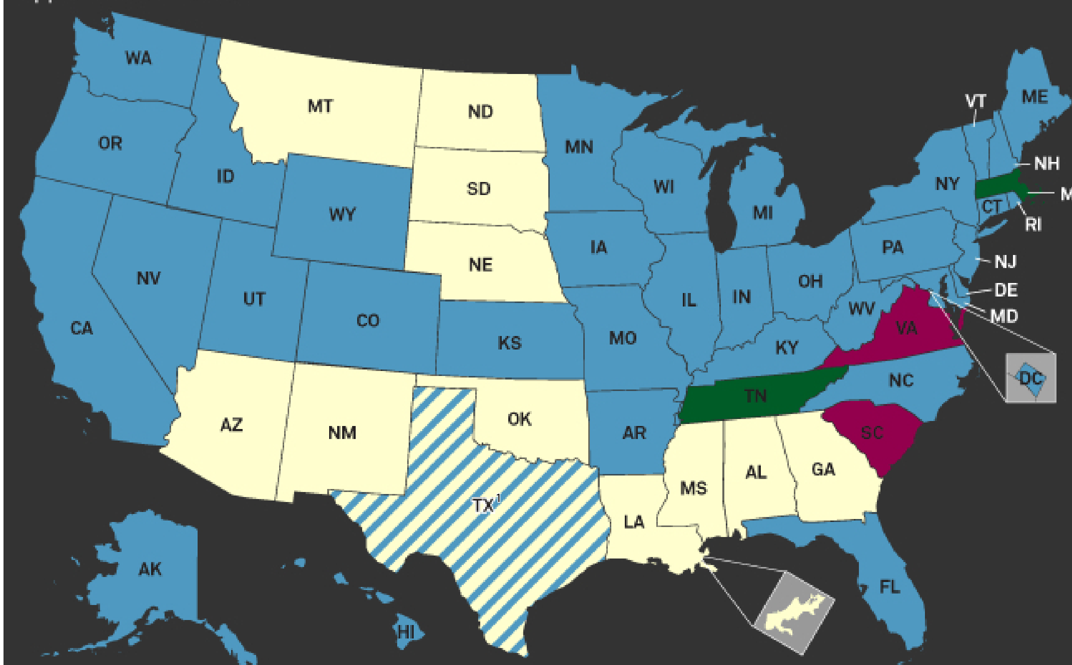
State Regulatory Evaluations

Commissioner selection method
Appointed vs. elected



Appointed | Direct voter elections; elected by district | Other | Elected by general assembly

Data as of Nov. 26, 2018.
[1] The Public Utility Commission of Texas members are appointed by the governor, while members of the Railroad Commission of Texas are elected in statewide elections.
Source: RRA, an offering of S&P Global Market Intelligence

For additional information concerning the selection process in each state and the make-up of the commissions, refer to the RRA Regulatory Focus Topical Special Report entitled The Commissioners.

Commission staff/consumer interest

Most commissions have a staff that participates in rate proceedings. In some instances the staff has a responsibility to represent the consumer interest, and in others the staff's statutory role is less defined. In addition, there may or may not be: additional state-level organizations that are charged with representing the interests of a certain class or classes of customers; private consortia that represent certain customer groups; and/or large-volume customers that intervene directly in rate cases.

Generally speaking, the greater the number of consumer intervenors, the greater the level of uncertainty for investors. The level of risk for investors also depends on the caliber and influence of the intervening parties and the level of contentiousness in the rate case process. Even though a commission may not adopt an extreme position taken by an intervenor, the inclusion of an extreme position in the record for the case widens the range of possible outcomes, reducing certainty and increasing the risk of a negative outcome for investors. RRA's opinion on these issues is largely based on past experience and observations.

Settlements

Generally speaking, the ability of the parties to reach agreement without having to go through a fully litigated proceeding is considered constructive. However, RRA also endeavors to ascertain whether the settlements arise because of a truly collaborative approach among the parties, or if they result from concern by the companies that the commissioners' views may be more extreme than the intervenors, or that the intervenors will take a much more extreme position in a litigated framework than in a closed-door settlement negotiation.

Rate case timing

For each state commission, RRA considers whether there is a set time frame within which a rate case must be decided, the length of any such statutory time frame and the degree to which the commission adheres to that time frame.

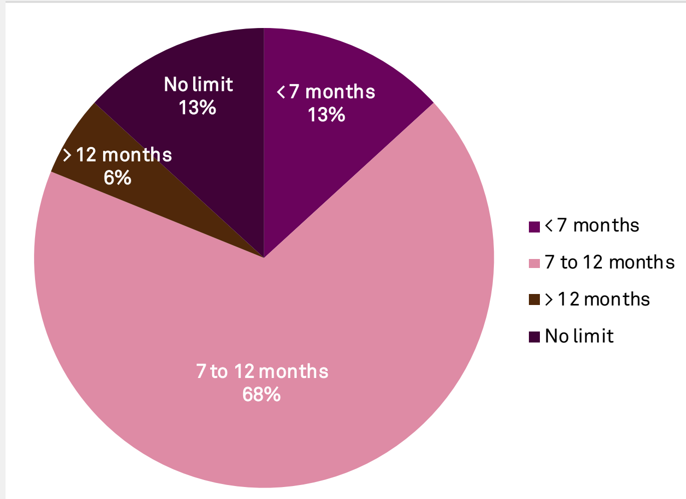
Generally speaking, RRA views a set time frame as preferable, as it provides a degree of certainty as to when any new revenue may begin to be collected.

About two-thirds of state commissions nationwide have a rule or statute that requires a rate case to be decided within seven to 12 months of filing.

Shorter time frames may apply for limited-issue proceedings, but there are very few states where a rate case will take less than seven months to be decided.

In addition, a shorter time frame for a decision generally reduces the likelihood that the actual conditions during the first year the new rates will be in effect will vary markedly from the test period utilized to set new rates, thus keeping regulatory lag to a minimum.

Rate case time frame



Data gathered as of Feb. 6, 2019
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Interim procedures

The ability to implement all or a portion of a proposed rate increase on an interim basis prior to a final decision in a rate case is viewed as constructive. However, should the commission approve a rate change that is markedly below the rates implemented on an interim basis, the utility would be required to refund any related overcollections, generally with interest.

In some instances commission approval is required prior to the implementation of an interim increase, and may or may not be easy to obtain, while in others state law or commission rules permit the companies to implement interim rate increases as a matter of course. In some instances, the commission may establish a date prior to the final decision in the case that will be the effective date of the new rates. In these instances, the company may be permitted to recoup any revenue that was not collected between the effective date and the decision date.

Rate base

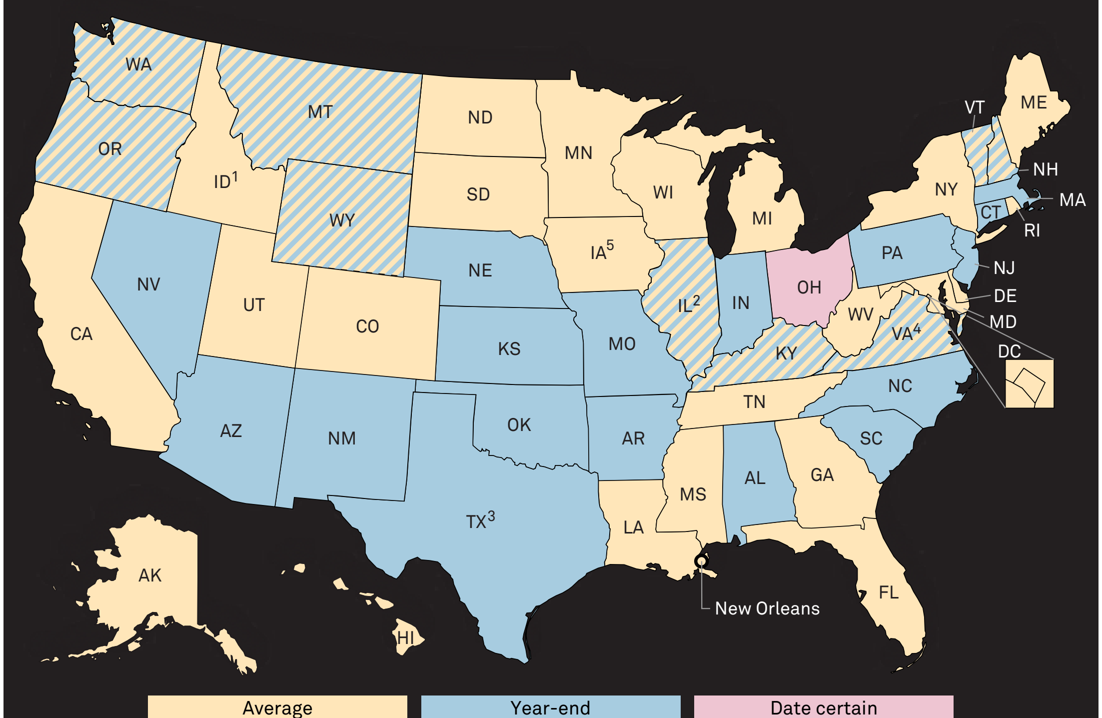
As noted above, a commission's policies regarding rate base can impact the ability of a utility to earn its authorized ROE. These policies are often outlined in state statutes, and the commission usually does not have much latitude with respect to these overall policies.

With regard to rate base, commissions are about evenly split between those that employ a year-end, or terminal valuation, and those that utilize an average valuation, with one using a "date certain." In some instances, the commission may employ a different rate base valuation method depending on the utility type or the type of case — general rate case or limited-issue proceeding.

In general, assuming rate bases are rising, i.e., new investment is outpacing depreciation, a year-end valuation is preferable from an investor viewpoint.

Again, this relates to how well the parameters used to set rates reflect actual conditions that will exist during the rate-effective period; hence, the more recent the valuation, the more likely it is to approximate the actual level of rate base being employed to serve customers once the new rates are placed into effect.

Rate base valuation method



Data as of Nov. 26, 2018.

[1] Major plant additions have been accorded year-end rate base treatment

[2] For utilities that are not under formula rate plans, an average rate base must be used if a projected test year is selected. For utilities under the plans, filings must reflect estimated net plant additions through the end of the year in which the case is filed.

[3] Both the Public Utility Commission of Texas and the Railroad Commission of Texas utilize a year-end rate base valuation.

[4] Certain utilities have characterized their rate cases as utilizing a forecast test year and an average rate base, while others have referred to it as a historical test year and a year-end rate base, with known and measurable adjustments.

[5] Pursuant to legislation enacted in 2018, the Iowa Utilities Board is drafting rules to allow the utilities to select the rate base valuation method and test-year type.

Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Some commissions permit post-test year adjustments to rate base for "known and measurable" items, and, in general, this practice is beneficial to the utilities. However, the rules with respect to what constitutes a known and measurable adjustment are not always specific, and there can be a good deal of controversy about what does and does not pass muster.

Another key consideration is whether state law and/or the commission generally permit the inclusion in rate base of construction work in progress, or CWIP, for a cash return. CWIP represents assets that are not yet, but ultimately will be, operational in serving customers.

Generally, investors view inclusion of CWIP in rate base for a cash return as constructive, since it helps to maintain cash flow metrics during a large construction cycle. Alternatively, the utilities accrue allowance for funds used during construction, or AFUDC, which is essentially booking a return on the construction investment as a regulatory asset that is recoverable from ratepayers once the project in question becomes operational.

While this method bolsters earnings, it does not augment cash flow and does not support credit metrics. For a more in-depth look at rate base issues, refer to the RRA report entitled Rate base: How would you rate your knowledge of this utility industry fundamental?

Test period

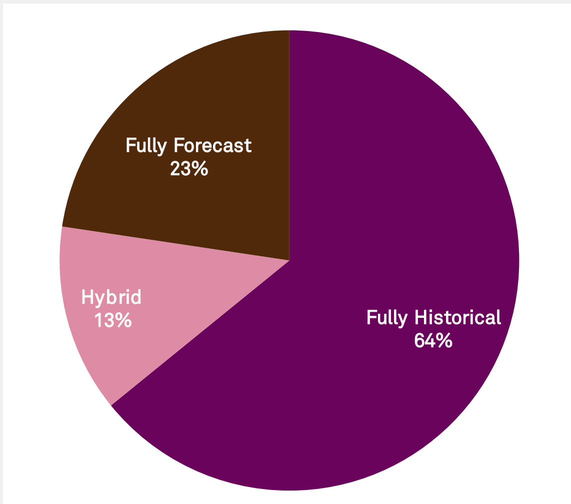
With regard to test periods, there are a number of different practices employed, with the extremes being fully forecast at the time of filing, which is considered to be most constructive, on the one hand, and fully historical at the time of filing, considered to be least constructive, on the other.

Some states utilize a combination of the two, in which a utility is permitted to file a rate case that is based on data that is fully or partially forecast at the time of filing and is later updated to reflect actual data that becomes known during the course of the proceeding.

Generally speaking, in these cases the test year is historical by the time a decision is ultimately rendered, and so regulatory lag remains something of a problem.

Almost two-thirds of the 53 jurisdictions covered by RRA utilize a test year that is historical at the time of filing. As with rate base valuation, in some states commissions use different test period types for different types of proceedings or for different utility types. The accompanying chart shows the predominant treatment.

Rate case test year



Data gathered as of Feb. 6, 2019.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Many of the jurisdictions allow for "known and measurable" adjustments to the test year, but the statutes governing the definition of known and measurable can be ambiguous, and there can be wide disagreement among the rate case parties as to which adjustments qualify.

Return on equity

ROE is perhaps the single most litigated issue in any rate case. There are two aspects RRA considers when evaluating an individual rate case and the overall regulatory environment: (1) how the authorized ROE compares to the average of returns authorized for energy utilities nationwide over the 12 months, or so, immediately preceding the decision; and

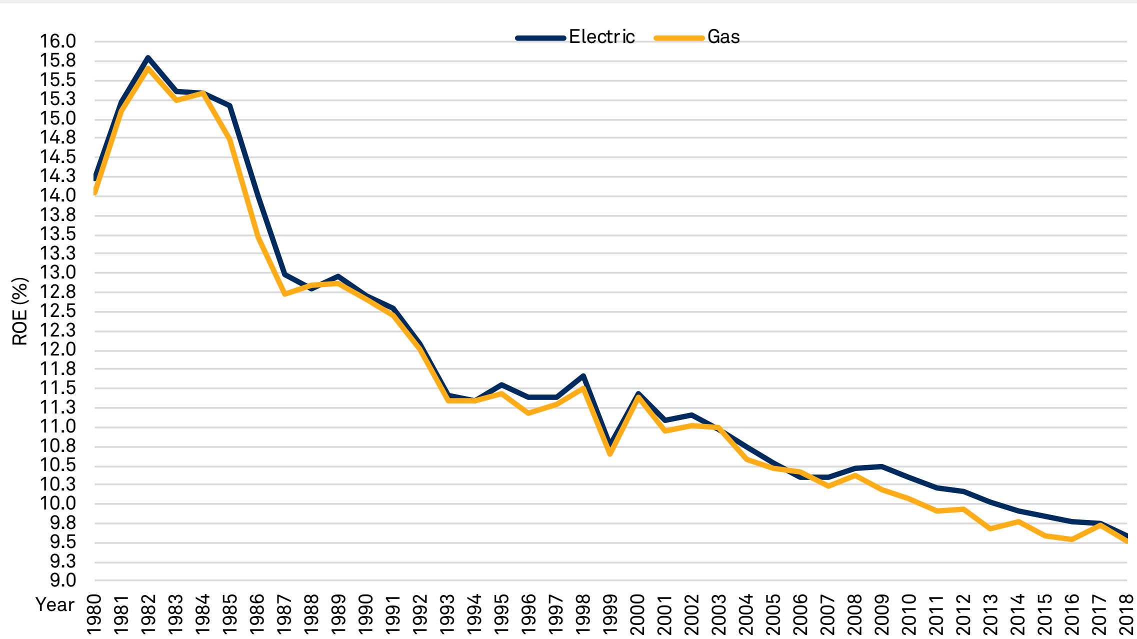
(2) whether the company has been accorded a reasonable opportunity to earn the authorized return in the first year of the new rates.

With regard to the first criterion, RRA looks at the ROEs historically authorized utilities in a given state and compares them to utility industry averages, as calculated in RRA's Major Rate Case Decisions Quarterly Updates.

As the chart shows, ROEs have been declining over the last three decades, falling below 10% in recent years. When referring to these "averages," RRA means the average ROE approved in cases decided in a particular year; returns carried over from prior years are not included in the averages.

Intuitively, authorized ROEs that meet or exceed the prevailing averages at the time established are viewed as more constructive than those that fall short of these averages.

Average authorized ROE in the US
Calendar years 1980-2018



Data compiled as of Jan. 31, 2019.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

With regard to the second consideration, in the context of a rate case, a utility may be authorized a relatively high ROE, but factors, such as capital structure changes, the age or "staleness" of the test period, rate base and expense disallowances, the manner in which the commission chooses to calculate test year revenue, and other adjustments, may render it unlikely that the company will earn the authorized return on a financial basis.

Even if a utility is accorded a "reasonable opportunity" to earn its authorized ROE, there is no guarantee that the utility will do so. The revenue requirement and ROE established in a rate case are targets that the commission believes the established rates will allow the utility to attain.

Various factors such as weather, management efficiency, unexpected events, demographic shifts, fluctuations in economic activity and customer participation in energy conservation programs may cause revenue and earnings to vary from the targets set.

Hence, the overall decision may be restrictive from an investor viewpoint even though the authorized ROE is equal to or above the average. For a more detailed discussion of the rate case process, refer to the RRA report entitled The Rate Case Process: A Conduit to Enlightenment.

Accounting

RRA looks at whether a state commission has permitted unique or innovative accounting practices designed to bolster earnings. Such treatment may be approved in response to extraordinary events such as storms or for volatile expenses such as pension costs. Generally, such treatment involves deferral of expenditures that exceed the level of such costs reflected in base rates. In some instances the commission may approve an accounting adjustment to temporarily bolster certain financial metrics during the construction of new generation capacity.

From time to time, commissions have approved frameworks under which companies were permitted to, at their own discretion, adjust depreciation in order to mitigate underearnings or eliminate an overearnings situation without reducing rates. These types of practices are generally considered to be constructive from an investor viewpoint.

Federal tax law changes enacted in 2017 and effective in 2018, particularly the reduction in the corporate federal income tax rate to 21% from 35%, had sweeping impacts for utilities, with a flurry of activity during 2018. While most states have addressed the issues, there are still some out there that have yet to do so. For most of the companies that have already addressed the implications with regulators, rates have been reduced to reflect the ongoing impact of the lower tax rate, refunds to return to ratepayers and related deferred overcollections are occurring over a relatively short time period, and amortization of the related excess accumulated deferred income tax liabilities is occurring over varying time periods — generally over the lives of the assets of 30 to 45 years for protected amounts and most often five to 10 years for unprotected amounts. RRA has been monitoring these developments and their impact on credit ratings and investor risk.

Alternative regulation

Generally, RRA views as constructive the adoption of alternative regulation plans that are designed to streamline the regulatory process and cost recovery or allow utilities to augment earnings in some way. These plans can be broadly or narrowly focused. Narrowly focused plans may: allow a company or companies to retain a portion of cost savings relative to a base level of some expense type, e.g., fuel, purchased power, pension cost, etc.; permit a company to retain for shareholders a portion of off-system sales revenues; or provide a company an enhanced ROE for achieving operational performance and/or customer service metrics or for investing in certain types of projects, e.g., demand-side management programs, renewable resources, new traditional plant investment.

The use of plans with somewhat broader scopes, such as ROE-based earnings sharing plans, is, for the most part, considered to be constructive, but it depends upon the level of the ROE benchmarks specified in the plan and whether there is symmetrical sharing of earnings outside the specified range.

Some states employ even more broad-based plans, such as formula-based ratemaking, where authorized return parameters are set at the inception of the plans and rates are permitted to adjust automatically on an annual basis within a certain range to reflect changes in expenses and new capital investment, similar to the paradigm in place for electric transmission at the Federal Energy Regulatory Commission.

Alternative reglation plans in the US*

Formula-based ratemaking	Multi-year rate plans	Earnings sharing	Incentive ROEs	Electric fuel/ gas costs	Capacity release/off-system sales
Alabama	California	Iowa	Colorado	Indiana	Colorado
Arkansas	Connecticut	Colorado	Iowa	Iowa	Delaware
Illinois	Florida	Georgia	Nevada	Kansas	Indiana
Louisiana	Georgia	New York	Virginia	Kentucky	Iowa
Mississippi	Massachusetts	Maine		Maryland	Kentucky
Texas	New York	Oklahoma		Missouri	Massachusetts
		Virginia		Montana	Missouri
				New Jersey	North Dakota
				Oregon	New Jersey
				Virginia	Pennsylvania
				Wyoming	Tennessee
					Texas
					Utah

As of Feb. 6, 2019.
ROE = return on equity
* Type of plan in place for at least on utility in the state. Listing is not comprehensive.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence.

Court actions

This aspect of state regulation is particularly difficult to evaluate. Common sense would dictate that a court action that overturns restrictive commission rulings is a positive. However, the tendency for commission rulings to come before the courts and for extensive litigation as appeals go through several layers of court review may add an untenable degree of uncertainty to the regulatory process. Also, similar to commissioners, RRA looks at whether judges are appointed or elected, as political considerations are more likely to influence elected jurists.

Legislation

While RRA's Commission Profiles provide statistics regarding the make-up of each state legislature, RRA has not found there to be any specific correlation between the quality of energy legislation enacted and which political party controls the legislature. Of course, in a situation where the governor and legislature are of the same political party, generally speaking, it is easier for the governor to implement key policy initiatives, which may or may not be focused on energy issues.

Key considerations with respect to legislation include: how prescriptive newly enacted laws are; whether the bill is clear or ambiguous and open to varied interpretations; whether it balances ratepayer and shareholder interests rather than merely "protecting" the consumer; and whether the legislation takes a long-term view or is a "knee-jerk" reaction to a specific set of circumstances.

Corporate governance

The term corporate governance generally refers to a commission's ability to intervene in a utility's financial decision-making process through required pre-approval of all securities issuances, limitations on leverage in utility capital structures, dividend payout limitations, ring-fencing and authority over mergers. Corporate governance may also include oversight of affiliate transactions.

In general, RRA views a modest level of corporate governance provisions to be the norm, and in some circumstances these provisions, such as ring-fencing, have protected utility investors as well as ratepayers. However, a degree of oversight that would allow the commission to "micromanage" the utility's operations and limit the company's financial flexibility would be viewed as restrictive.

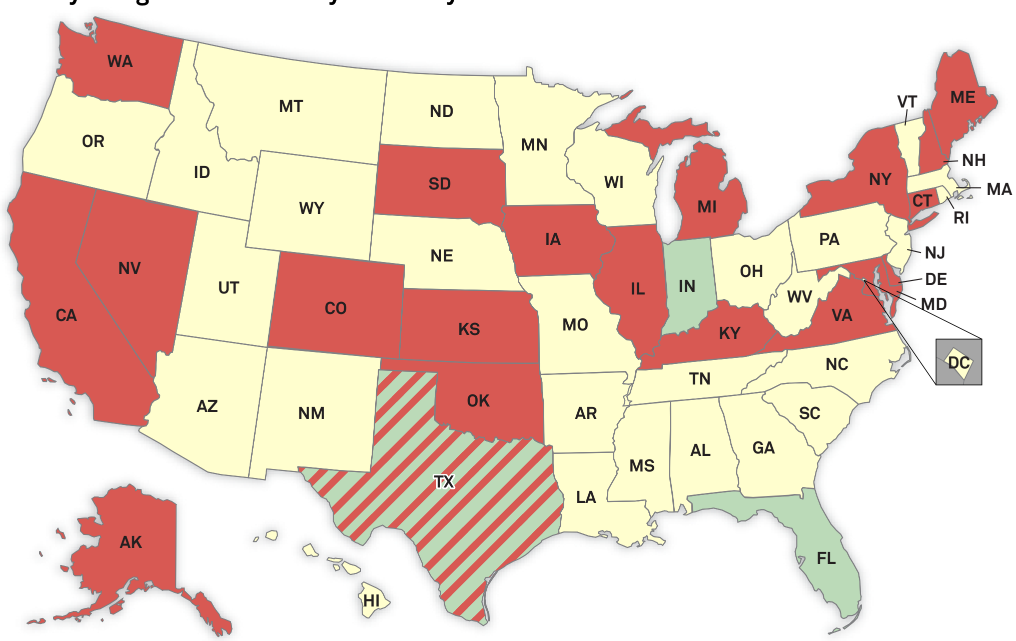
Merger activity

In cases where the state commission has authority over mergers, RRA reviews the type of approval standard that is contained in state law and/or has been applied by the commission in specific situations. Generally speaking, RRA views a "no net harm" standard as more constructive than a "positive net benefits approach." However, the statutes surrounding merger approvals are often open-ended, leaving much to the interpretation of the commission. Consequently, the review standard may be more apparent through examination of individual proceedings rather than statutes.

In evaluating a commission's stance on mergers, RRA looks at several broad issues such as whether there is a statutory time frame for consideration of a transaction and how long the process actually took. In addition, RRA considers whether a settlement was reached among the parties and if so, whether the commission honored that settlement or required additional commitments. RRA also examines how politicized the process was — Did the governor, or in the District of Columbia, the Mayor, play a role? Did the transaction garner a lot of local media attention in the affected jurisdiction?

More narrowly, RRA reviews the conditions placed on the commission's approval of these transactions, including: whether the company will be permitted to retain a portion of any merger-related cost savings; if guaranteed rate reductions or credits are required that are or are not directly related to merger savings; whether certain assets were required to be divested; what type of local control and work force commitments are required; whether there are requirements for certain types of investment to further the state's public policy goals that may or may not be consistent with the companies' business models and whether the related costs will be recoverable from ratepayers; and, whether the commission placed stringent limitations on capital structure and/or dividend policy or composition of the board of directors.

Utility mergers — statutory authority



No statutory authority | Authority with no statutory timeframe | Authority with statutory timeframe

S&P Global
Market Intelligence

As of Jan. 31, 2019.
In Texas, commission review of mergers involving electric utilities are subject to commission review; mergers of local gas distribution companies are not.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence
Map credit: Junaid Rehman

See the Merger Activity section of each Commission Profile for additional detail on statutory guidelines for merger reviews and detail concerning approved/rejected mergers and the associated conditions imposed.

Electric regulatory reform/industry restructuring

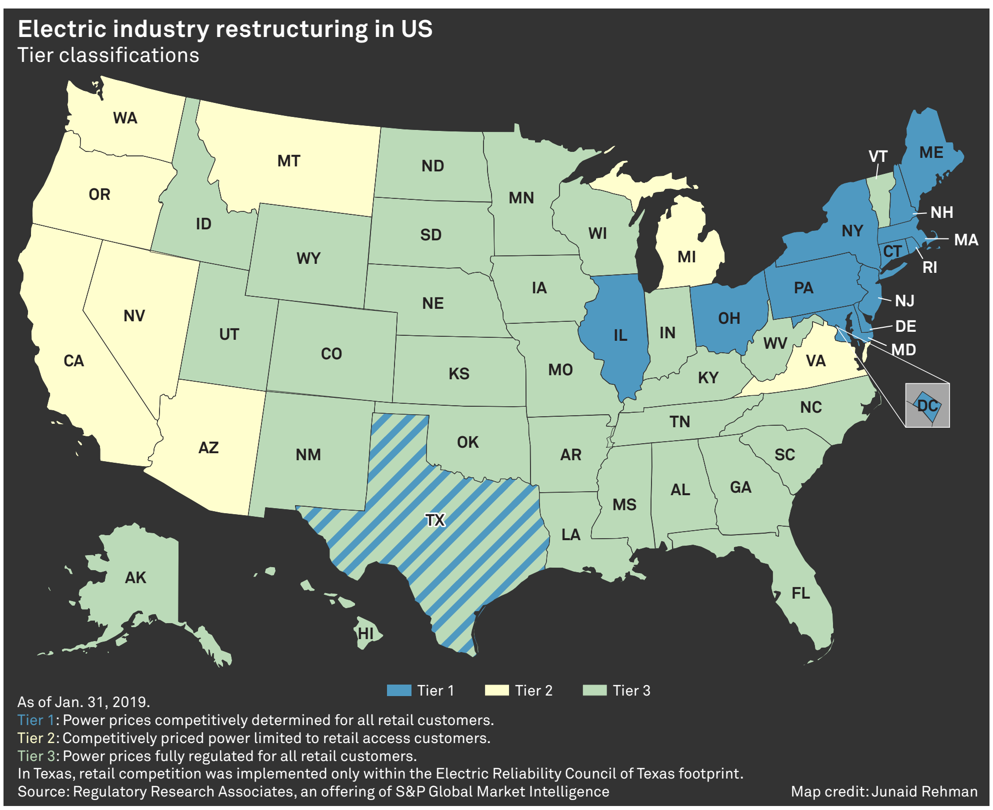
By electric industry restructuring, RRA means implementing a framework under which some or all retail customers have the opportunity to obtain their generation service from a competitive supplier. In a movement that began in the mid-1990s, about 20 jurisdictions have implemented retail competition. The last of the transition periods ended as recently as 2011, when restructuring-related rate freezes concluded for certain Pennsylvania utilities.

RRA classifies each of the regulatory jurisdictions into one of three tiers based on their relative electric industry restructuring status. The three Tiers are defined as follows.

Tier 1 — Power prices are competitively determined for all retail customers, both standard-offer-service and retail-access customers. Retail access is permitted for all customers. For the most part, the utilities in these states do not own generation. Please note that RRA has classified Texas as a Tier1 state even though retail competition is only available for customers served by utilities that are within the Electric Reliability Council of Texas footprint.

Tier 2 — Competitively priced power is limited to retail access customers. Retail access is permitted on at least a limited basis. Power prices for standard-offer-service customers remain regulated. For the most part, utilities remain vertically integrated.

Tier 3 — Power prices are fully regulated for all retail customers. All retail customers must purchase their power from the franchised utility.



RRA generally does not view a state's decision to implement retail competition for generation as either positive or negative from an investor viewpoint. However, how the transition occurred has been a key part of RRA's evaluation of jurisdiction. Issues considered by RRA include whether up-front rate reductions were required, the length of the transition periods and how stranded costs were addressed. Now that transition periods are completed, RRA has focused more on how standard-offer or default service is procured for customers who do not select an alternative provider and how much, if any market-price risk the utility must absorb.

In recent years the dual emphasis on renewables expansion and grid reliability/resiliency has called into question the efficacy of the traditional utility framework, and the U.S. electric industry appears to be on the cusp of a second phase of broad-based industry restructuring — one that may change the way the transmission and distribution system is configured. As these issues unfold, the same issues that were of concern in the first phase of restructuring will warrant close attention.

Gas regulatory reform/industry restructuring

Retail competition for gas supply is more widespread than is electric retail competition, and the transition was far less contentious as the magnitude of potential stranded asset costs was much smaller. Similar to electric retail competition, RRA generally does not view a state's decision to implement retail competition for gas service as either positive or negative from an investor viewpoint. RRA primarily considers the manner in which stranded costs were addressed and how default-service obligation-related costs are recovered.

Securitization

Securitization refers to the issuance of bonds backed by a specific existing revenue stream that has been "guaranteed" by regulators. State commissions have used securitization to allow utilities to recover demand-side management costs, electric-industry-restructuring-related stranded costs, environmental compliance costs and storm costs. RRA views the use of this mechanism as generally constructive from an investor viewpoint, as it virtually eliminates the recovery risk for the utility.

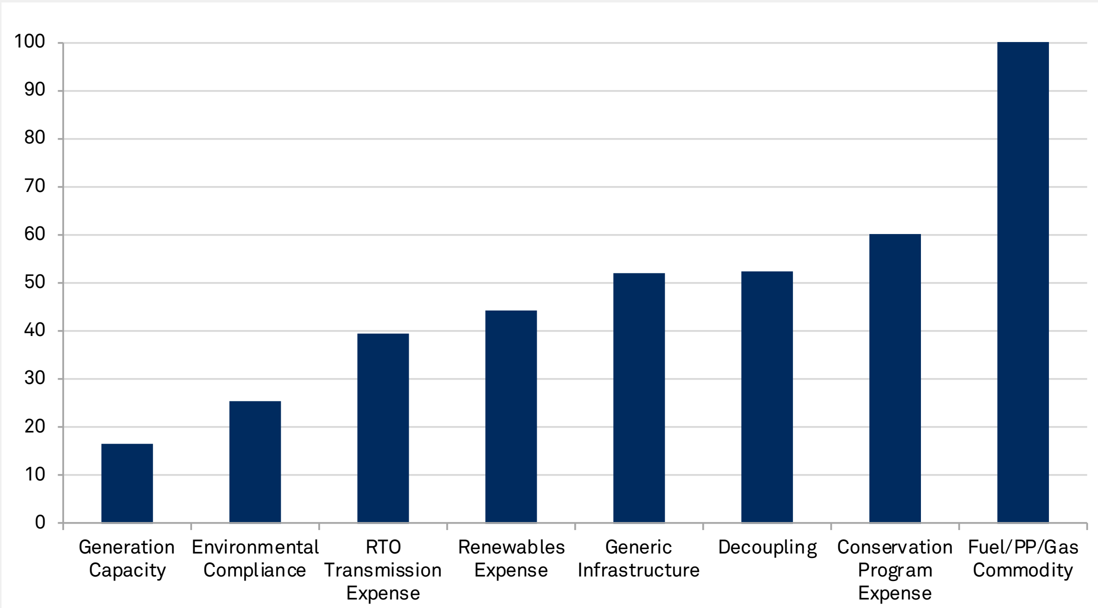
Adjustment clauses

Since the 1970s, adjustment clauses have been widely utilized to allow utilities to recover fuel and purchased power costs outside a general rate case, as these costs are generally subject to a high degree of variability. In some instances, a base amount is reflected in base rates, with the clause used to reflect variations from the base level, and in others, the entire annual fuel/purchased power cost amount is reflected in the clause.

Over time, the types of costs recovered through these mechanisms were expanded in some jurisdictions to include such items as pension and healthcare costs, demand-side management program costs, Federal Energy Regulatory Commission-approved regional transmission organization, or RTO, costs, new generation plant investment and transmission and distribution infrastructure spending. Generally, RRA views the use of these types of mechanisms as constructive but also looks at the frequency with which the adjustments occur, whether there is a true-up mechanism, whether adjustments are forward-looking in nature where applicable, whether a cash return on construction work in progress is permitted and whether there may be some ROE incentive for certain types of investment.

Other mechanisms that RRA views as constructive are weather-normalization clauses that are designed to remove the impact of weather on a utility's revenue, referred to as partial decoupling mechanisms, and full decoupling mechanisms that may remove not only the impact of weather but also the earnings impacts of customer participation in energy efficiency programs and sales volatility stemming from fluctuations in the overall economic health of the service territory.

Adjustment clauses in use (%)



As of Sept. 19, 2018.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Generally, an adjustment mechanism would be viewed as less constructive if there are provisions that limit the utility's ability to fully implement revenue requirement changes under certain circumstances, e.g., if the utility is earning in excess of its authorized return.

See the RRA Regulatory Focus Topical Special Report entitled Adjustment Clauses — A State-by-State Overview for additional detail.

Integrated resource planning

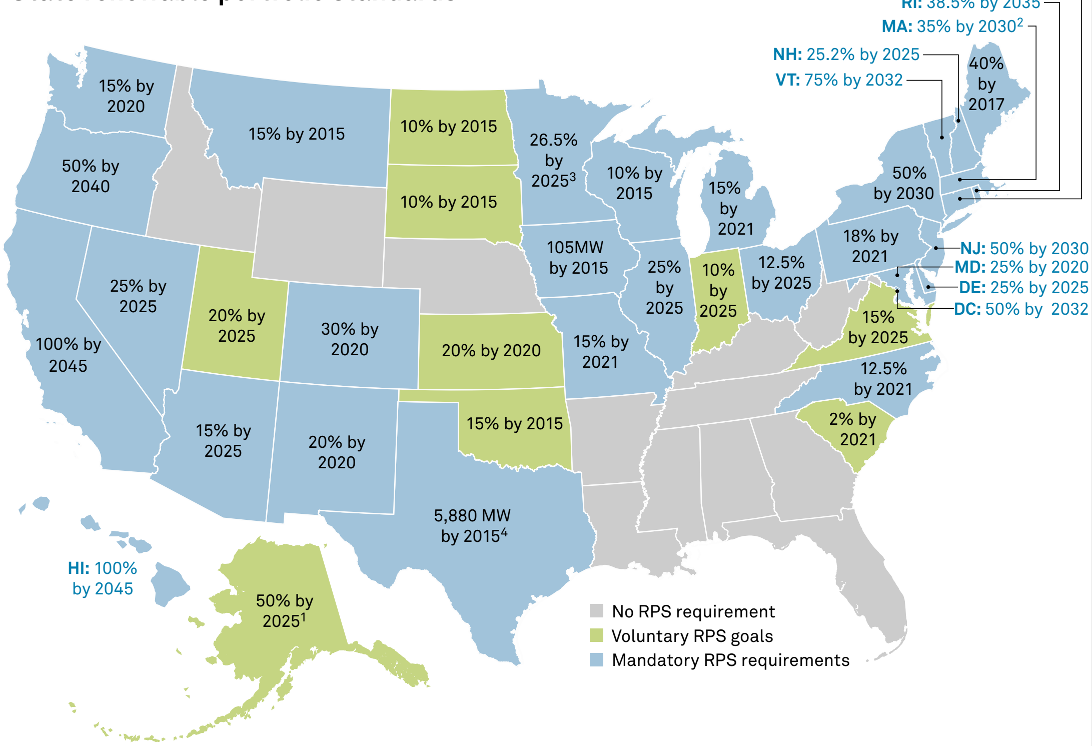
RRA generally considers the existence of a resource-planning process to be constructive from an investor viewpoint, as it may provide the utility at least some measure of protection from hindsight prudence reviews of its resource acquisition decisions. In some cases, the process may also provide for pre-approval of the ratemaking parameters and/or a specific cost for the new facility. RRA views these types of provisions as constructive, as the utility can make more informed decisions as to whether it will proceed with a proposed project.

Renewable energy/emissions requirements

As with retail competition, RRA does not take a stand as to whether the existence of renewable portfolio standards, ot RPS, or an emissions reduction mandate is positive or negative from an investor viewpoint. However, RRA considers whether there is a defined pre-approval and/or cost-recovery mechanism for investments in projects designed to comply with these standards.

RRA also reviews whether there is a mechanism such as a rate increase cap that ensures that meeting the standards does not impede the utility's ability to pursue other investments and/or recover increased costs related to other facets of its business. RRA also looks at whether incentives, such as an enhanced ROE, are available for these types of projects.

State renewable portfolio standards



Data as of Jan. 11, 2019.

[1] While the goal is not present in codified statues, House Bill 306, which sets the 50% RPS goal, was signed in July 2010 and went into effect that September.

[2] The state's requirement is to increase by an additional 2% annually beginning in 2020 through 2029, after which it is to increase by an additional 1% annually indefinitely.

[3] Any electric utility that owned a nuclear generating facility as of Jan. 1, 2007, e.g., Northern States Power-Minnesota, generate or procure 30% of retail sales from renewables and an additional 1.5% from solar by 2030.

[4] Texas PUC rules call for the utilities to "ensure that the means exist to achieve a target of 10,000 MW of installed renewable capacity by January 1, 2025."

Credit: Cat Weeks

Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

In recent years, the focus on renewables has surged across the United States, with all but 12 jurisdictions developing some type of RPS. The proliferation of renewables, particularly those that are customer-sited or distributed resources, and the related rise of battery storage and electric vehicles have raised questions regarding the traditional centralized industry framework and whether that framework needs to change, perhaps ushering in a second phase of electric industry restructuring. How these changes are implemented is something RRA will be watching closely.

With respect to emissions, the threat of a federal carbon emissions standard for utilities and the spread of state-level initiatives has caused many companies to rethink legacy coal-fired generation, causing plants to be shut down earlier than anticipated. How the commissions address these "stranded costs" also poses a risk for investors and bears monitoring.

The zero-carbon movement has also caused utilities/states to re-examine investments in nuclear facilities and in some cases, to develop programs designed to support the continued operation of those facilities, even though they may not be economic from a competitive-markets standpoint.

Rate structure

RRA looks at whether there are economic development or load-retention rate structures in place, and if so, how any associated revenue shortfall is recovered.

RRA also looks at whether there have been steps taken over recent years to reduce/eliminate interclass rate subsidies, i.e., to equalize rates of return across customer classes.

In addition, RRA considers whether the commission has adopted or moved toward a straight-fixed-variable rate design, under which a greater portion of a company's fixed costs are recovered through the fixed monthly customer charge, thus according the utility greater certainty of recovering its fixed costs. This is increasingly important in an environment where weather patterns are more volatile, organic growth is limited due to the economy and the proliferation of energy efficiency/conservation programs, and large amounts of non-revenue-producing capital spending is required to upgrade and strengthen the grid.

Fixed vs. variable costs

Fixed	Variable
Depreciation	Gas commodity
Delivery O&M	Electric commodity
Property taxes	Generation O&M
Return on investment	
Customer service	

As of Feb. 6, 2019.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence.

In conjunction with the influx of renewables and distributed generation, the issue of how to compensate customer-owners for excess power they put back into the grid has become increasingly important and in some instances controversial. How these pricing arrangements, known as net metering, are structured can impact the ability of the utilities to recover their fixed distribution system costs and by extension their ability to earn their authorized returns..

Contributors: *Sara Bellizzi, Jim Davis, Russell Ernst, Lisa Fontanella, Monica Hlinka, Dan Lowrey and Amy Poszywak*.

Scotiabank™ Xcel Energy

Indicative New Issue Spreads

Friday, May 31, 2019

New Issue Spreads	5 Year	10 Year	30 Year
UST Reference Bond	2.000 05/24	2.375 05/29	3.000 02/49
Reference Yield	1.90%	2.15%	2.55%
Xcel Energy Inc. (Baa1/BBB+)			
Indicative Spreads	**+85 area**	**+115 area**	**+140 area**
Indicative Coupon	2.75%	3.30%	3.95%
Swapped to US$ LIBOR	L+85	L+119	L+168
Northern States Power - Minnesota (Aa3/A)			
Indicative Spreads	**+55 area**	**+85 area**	**+110 area**
Indicative Coupon	2.45%	3.00%	3.65%
Swapped to US$ LIBOR	L+55	L+89	L+138
Northern States Power - Wisconsin (Aa3/A)			
Indicative Spreads	**+55 area**	**+85 area**	**+110 area**
Indicative Coupon	2.45%	3.00%	3.65%
Swapped to US$ LIBOR	L+55	L+89	L+138
Public Service Company of Colorado (A1/A)			
Indicative Spreads	**+65 area**	**+95 area**	**+115 area**
Indicative Coupon	2.55%	3.10%	3.70%
Swapped to US$ LIBOR	L+65	L+99	L+143
Southwestern Public Service (A3/A)			
Indicative Spreads	**+75 area**	**+105 area**	**+130 area**
Indicative Coupon	2.65%	3.20%	3.85%
Swapped to US$ LIBOR	L+75	L+109	L+158

IG Market Stats

This Week's IG Issuance: $5.85 B
2019 YTD IG Issuance: $525.62 B
Average IG Index: + 131 bps

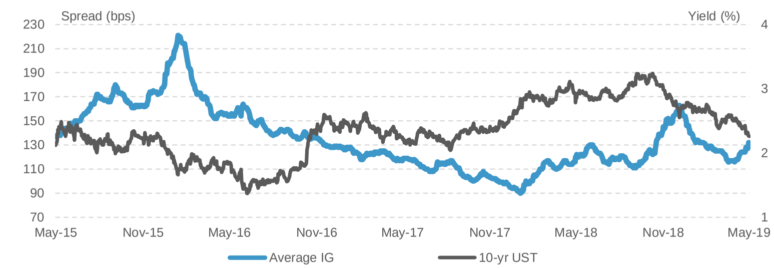
Economic Data Releases (6/3/2019 - 6/7/2019)

Monday: Markit US Manufacturing PMI, ISM Manufacturing, Construction Spending
Tuesday: Factory Orders, Durable Goods Orders, Cap Goods Orders
Wednesday: ADP Employment Change, Markit US Services PMI, Markit US Composite PMI, ISM Non-Manufacturing Index
Thursday: Trade Balance
Friday: Nonfarm Payrolls, Manufacturing Payrolls, Unemployment Rate, Wholesale Inventories

Recent Transactions

Date	Issuer	Ratings	Amt	Maturity	Spread
30-May	Southern California Gas	Aa2/A+	$350M	Feb-50	+130
30-May	Entergy Mississippi	A2/A	$300M	Jun-49	+127
28-May	San Diego Gas & Electric	A2/A	$400M	Jun-49	+140
28-May	Pennsylvania Electric	Baa1/BBB	$300M	Jun-29	+135
28-May	Southwest Gas	A3/BBB+	$300M	Jun-49	+145
22-May	Consumers Energy	Aa3/A	$300M	Feb-50	+100
21-May	Piedmont Natural Gas	A3/A-	$600M	Jun-29	+110

Average IG Credit Spreads & 10-yr UST Yield



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