DOCKET NO. ________

APPLICATION OF SOUTHWESTERN	**§**	**PUBLIC UTILITY COMMISSION**
PUBLIC SERVICE COMPANY FOR	**§**	
AUTHORITY TO CHANGE RATES	**§**	**OF TEXAS**

DIRECT TESTIMONY
of
SARAH SOONG

on behalf of

SOUTHWESTERN PUBLIC SERVICE COMPANY

(*Filename:* SoongRRDirect.docx)

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
CCR	Corporate Credit Rating
CFO	Cash from Operations
Commission	Public Utility Commission of Texas
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
FFO	Funds from Operations
Fitch	Fitch Ratings
Moody's	Moody's Investors Service
ROE	Return on Equity
RFP	Rate Filing Package
S&P	Standard & Poor's
SPS	Southwestern Public Service Company, a New Mexico corporation
Test Year	April 1, 2018 through March 31, 2019
Update Period	April 1, 2019 through June 30, 2019
WACC	Weighted Average Cost of Capital
W/C	Working Capital
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc

LIST OF ATTACHMENTS

Attachment	**Description**
SWS-RR-1	Statement of Qualifications (*Filename:* SWS-RR-1.docx)
SWS-RR-2	Moody's October 19, 2018: Rating Action: Moody's Changes Xcel Energy's outlook to negative; downgrades Southwestern Public Service ratings to Baa2 with stable outlook (*Non-native format*)
SWS-RR-3	Moody’s: Regulated Electric and Gas Utilities (*Non-native format*)
SWS-RR-4	Standard & Poor’s: Key Credit Factors for the Regulated Utilities Industry (*Non-native format*)
SWS-RR-5	Moody’s Credit Opinion: CenterPoint Energy Houston Electric, LLC (*Non-native format*)
SWS-RR-6	Credit Ratings Descriptions (*Filename:* SWS-RR-6.xlsx)
SWS-RR-7	S&P’s Corporate Methodology: Ratios and Adjustments. (*Non-native format*)
SWS-RR-8	Fitch July 11, 2019: FitchRatings: Corporates-Southwestern Public Service Company (*Non-native format*)
SWS-RR-9	S&P Global Market Intelligence: Public Utility Commission of Texas (*Non-native format*)

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. ("XES") 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-RR-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 Public Service Company of Colorado's steam and electric base rate cases, Case Nos. 19AL-0063ST and 19AL-0268E as well as New Mexico Public Regulation Commission in SPS's electric base rate case, No. 19-00170-UT.

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 Test Year[1] at 7.65% and for the Update Period[2] at 7.62%. 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;
- Present and support the use of actual capital structure, which consists of 54.65%equity and 45.35% long-term debt, as of the end of the Historical Test Year and the Update Period; and
- Present and support SPS's Test Year and Update Period cost of long-term debt, which were 4.40% and 4.33%, respectively.

[1] The "Test Year" is the Historical Test Year Period consisting of April 1, 2018 through March 31, 2019.

[2] The "Update Period" is April 1, 2019 through June 30, 2019.

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

A. Yes, I am sponsoring the following attachments:

- Attachment SWS-RR-1, which is a description of my qualifications and responsibilities;
- Attachment SWS-RR-2, which is a Moody's Investors Service ("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-RR-3, which is a Moody's publication entitled Regulated Electric and Gas Utilities;
- Attachment SWS-RR-4, which is a Standard & Poor's ("S&P") publication entitled Key Credit Factors for the Regulated Utilities Industry;
- Attachment SWS-RR-5, which is a Moody's publication entitled Credit Opinion: CenterPoint Energy Houston Electric, LLC;
- Attachment SWS-RR-6, which is a description of the major credit rating agencies' credit ratings;
- Attachment SWS-RR-7, which is an S&P publication entitled Corporate Methodology: Ratios and Adjustments;
- Attachment SWS-RR-8, which is a Fitch Ratings ("Fitch") publication entitled FitchRatings: Corporates-Southwestern Public Service Company; and
- Attachment SWS-RR-9, which is an S&P Global Market Intelligence publication, entitled Public Utility Commission of Texas.

In addition, I sponsor or co-sponsor the Rate Filing Package ("RFP") Schedules set forth below:

- Schedule K-1 provides SPS's overall rate of return as a weighted average of each class of capital based upon SPS's capitalization at the end of the Test Year, including Update Period items as well as SPS's proposed capital structure and cost of capital. The cost of debt capital, the return on stockholder's equity, and the component amounts of each class of capital are presented and agree with supporting Schedules K-2, K-3, and K-4. In addition, this schedule presents the overall rate of return on the original cost of rate base and the resulting total return (capital cost) expressed in dollars. That portion of the schedule is sponsored by SPS witness Arthur P. Freitas.
- Schedule K-2 is intended to provide the weighted average cost of preferred stock capital. Because SPS has no preferred stock, the schedule is not applicable.
- Schedule K-3 contains a schedule of the weighted average cost of long-term debt capital and lists each debt issue for each class and series of long-term debt outstanding, according to the balance sheet as of the end of the Test Year and Update Period.
- Schedule K-4 provides information pertaining to SPS's notes payable, although notes payable are not included in the capital structures provided in Schedule K-1. The schedule also includes a description of any significant

changes anticipated in the balance of notes payable during the twelve-month period following the Test Year.

- Schedule K-5 provides a description and calculation of the most restrictive financial tests as of the end of the Test Year pertaining to the issuance of securities or the maintenance of banking lines of credit.
- Schedule K-6 provides historical financial ratios for the Test Year and the five fiscal years preceding the Test Year, as well as forecast data through 2022. In addition, Schedule K-6 provides the definition of the ratios.
- Schedule K-7 provides estimates of the requirements for and sources of future capital for three or five fiscal years following the Test Year, with explanations of all assumptions and estimates used.
- Schedule K-8 provides historical financial information necessary to calculate earnings per share, dividends per share, and book value per share over the previous 16 fiscal years, with the weighted average number of shares adjusted for stock splits. Compound growth rates and average values for ROE and earnings retention are provided for these measures over the most recent five-, ten-, and fifteen-year periods. The amount of any non-recurring gains or losses is provided for each year along with a book description of the non-recurring event, if appropriate. Finally, a calculation of the year-end market-to-book ratio is provided for each year.
- Schedule K-9 contains copies of all credit rating analyses or investment reports on SPS and Xcel Energy published during the most recent 12-month

period and in the possession of SPS, including but not limited to reports by S&P, Moody's, and Fitch.

Q. Please summarize the recommendations in your testimony.

A. I recommend that the Public Utility Commission of Texas ("Commission") approve SPS's Update Period WACC as shown in Table SWS-RR-1.

Table SWS-RR-1: Proposed Cost of Capital

Update Period		**Forecast June 30, 2019**	
	Ratio	**Rate**	**Wtd Cost**
Long-Term Debt	45.35%	4.33%	1.96%
Equity	54.65%	10.35%	5.66%
Total Cost			**7.62%**

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, which includes 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 with the rate proceeding outcomes in New Mexico and 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 achieve a supportive regulatory outcome in Texas that is responsive to concerns raised by the rating agencies regarding the Texas regulatory environment

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 Return on Equity ("ROE") of 10.35% as supported by SPS witness Ann E. Bulkley in this case would be a positive step 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.

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 required investment in SPS's generation resources and transmission and distribution system. Finally, rating agencies will be looking at the Commission's decision in this case as an indication of whether Texas provides a balanced and constructive regulatory environment that compliments and supports the State's priority of economic growth.

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 financial integrity was largely the result of investor concern with the regulatory environment and regulatory support or lack thereof that SPS was experiencing.[3] 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.

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[3] Attachment SWS-RR-2

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 Cash From Operations (“CFO”) pre-Working Capital (“W/C”) to debt above 18% for an extended period of time.

Q. How much capital has SPS invested in its system over the last several years and how much does SPS expect to invest over the next five years?

A. During the five year period from 2014 to 2018, SPS spent approximately $3.25 billion in capital. SPS plans to spend another $3.52 billion during the five-year period from 2019-2023 as shown on Table SWS-RR-2.

Table SWS-RR-2: SPS Capital Investment

Year	SPS Capital Investment or Planned Capital Investment[4]
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. Will the capital structure adopted in this rate case impact SPS's ability to fund these capital needs?

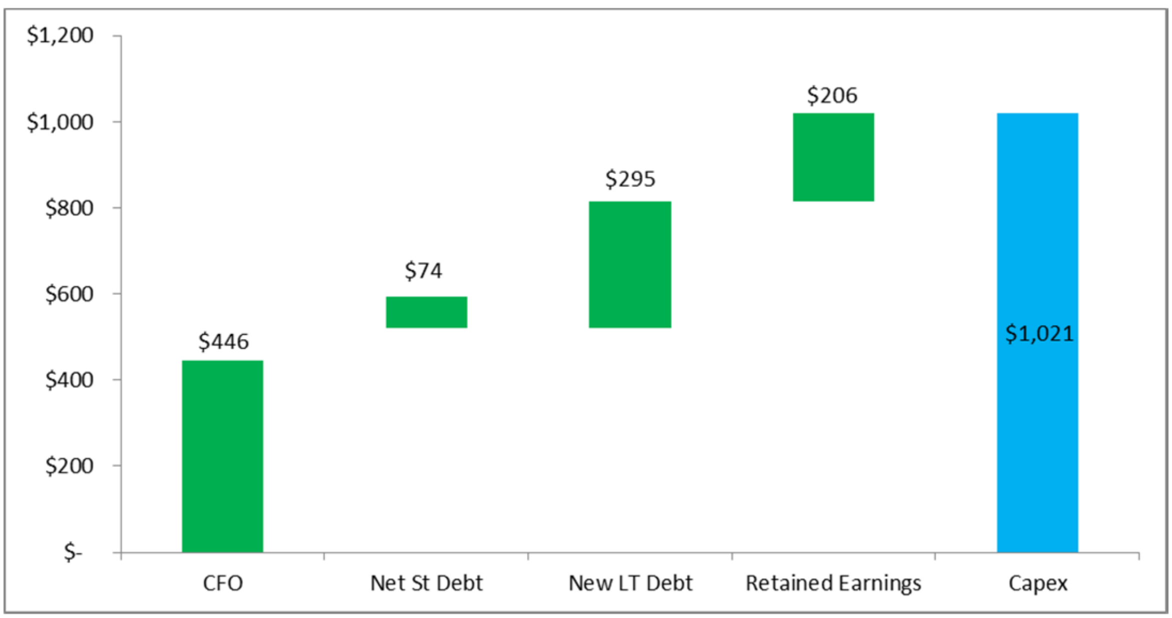
A. Yes. SPS funds its capital needs through a combination of (1) retained earnings or by receiving capital infusions from its parent company; and (2) borrowing. Retained earnings result from equity derived from cash received from customer revenues within SPS (rather than sending those excess funds as 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 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.

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

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 CFO in 2018 as seen in Chart SWS-RR-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-RR-1: 2018 Sources of Funding for Capital Spend



SPS is forecasting a similar percentage 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-RR-2 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 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 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.[5] Credit ratings are assigned after the agencies conduct an independent, comprehensive

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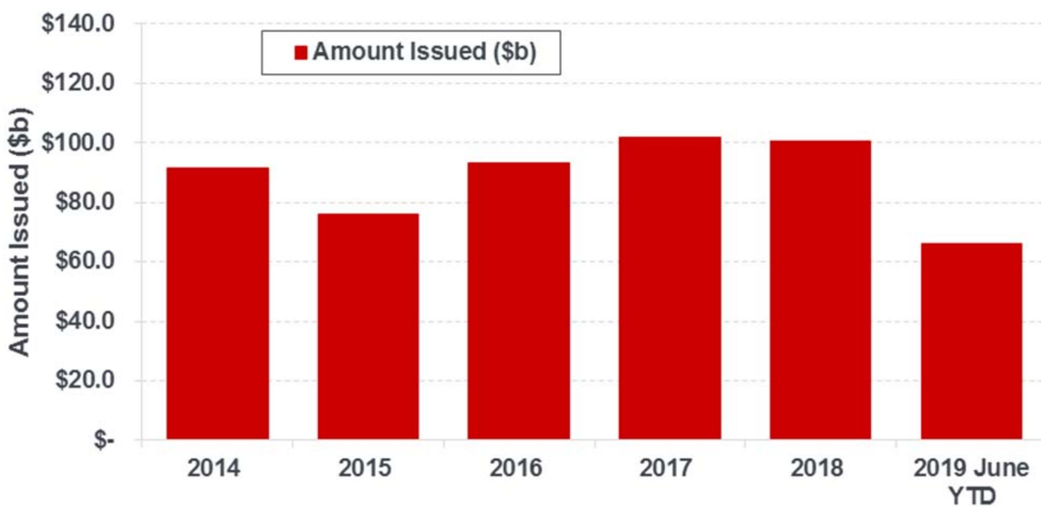
[5] Business risk relates to the potential sources of variability in a company's cash flow from its operating conditions as a result of various business factors including: regulatory environment and trends, operational performance, regulatory outcomes, fuel mix and geographic dispersion, and management 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 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 investment dollars. During the past five and a half years, debt investors have provided approximately $530 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-RR-2.

Chart SWS-RR-2: 2014-June 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-

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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.

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 the 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-RR-3: 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."[6]

The second factor, the "Ability to Recover Costs and Earn Returns," is also fundamentally dependent on Commission actions. Moody's evaluates the

[6] Attachment SWS-RR-3 at 6.

regulatory elements that directly affect the ability of the utility to generate cash flow and service its debt over time.[7] Moody's views the ability to recover costs on a timely basis and to attract debt and equity capital as crucial 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."[8] 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.[9]

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.[10]

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

[7] Attachment SWS-RR-3 at 12.

[8] Attachment SWS-RR-3 at 12.

[9] 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.

[10] Attachment SWS-RR-3 at 16.

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.[11]

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."[12] S&P observes further that "[w]e base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability; efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return."[13] 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

[11] Attachment SWS-RR-3 at 20.

[12] Attachment SWS-RR-4 at 6.

[13] Attachment SWS-RR-4 at 6.

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.

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.

This is illustrated by Moody's statement in a Credit Opinion for CenterPoint Energy Houston Electric, LLC (CEHE) issued in June 2019, which states: "CEHE's credit profile incorporates our expectation of a continued supportive regulatory environment."[14] They also maintain, "The outcome of the utility's pending rate case, expected by October, will be important in determining the future financial strength of the utility."[15] These statements from Moody's about a Texas based utility demonstrate the importance of rate case outcomes and their subsequent impact on a company's credit profile and financial strength to rating agencies.

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[14] Attachment SWS-RR-5 at 1.

[15] Attachment SWS-RR-5 at 1.

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.[16] The highest investment-grade rating is AAA; the lowest investment-grade rating is BBB-. Debt rated BB+ or below is considered speculative grade. Attachment SWS-6 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

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

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.[17] Expressed in terms of equity ratio as used in Commission proceedings, approval of SPS's requested 45.35% debt to 54.65% 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-RR-8 below. This would

[17] 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-7 for discussion on S&P's Corporate Methodology: Ratios and Adjustments.

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 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. At this time, 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-RR-4:

Table SWS-RR-4: S&P's Financial Ratios and Risk Matrices

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-RR-4.

A. Table SWS-RR-4 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-RR-5.

Table SWS-RR-5 – Moody's Financial Risk Factors

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-RR-5

A. Table SWS-RR-5 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 stated that a CFO pre-WC/Debt ratio of less than 16% could result in a downgrade to SPS's ratings[18].

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 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

[18] Attachment SWS-RR-2 at 2.

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.

C. <u>SPS's Financial Integrity and Credit Metrics</u>

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 ("CCR") of A- from S&P and BBB from both Moody's and Fitch, as reflected in Table SWS-RR-6 below**.**

Table SWS-RR-6: SPS's Current Corporate Credit Ratings

	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 rating of SPS "family" rating

** Although Fitch placed SPS "Under Criteria Observation" in April 2019 a short-term debt credit rating of F2 reflects the satisfactory capacity of obligor to meet its financial commitments

SPS's ratings were downgraded by Moody's in October 2018 as shown in Table SWS-RR-7[19]:

Table SWS-RR-7: SPS's Downgraded Corporate Credit Ratings

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.

[19] Attachment SWS-RR-2 at 2.

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."[20]

Similarly, in a report dated July 11, 2019, 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) 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."[21]

In the S&P Global Market Intelligence: Public Utility Commission of Texas dated May 2017[22], S&P cites, "Regulatory Research Associates… views the regulatory climate in Texas as somewhat more restrictive than average from an investor viewpoint... the Commission continues to rely on test years that are historical at the time a case is filed for both rate cases and capital recovery mechanisms . . . There has been quite a bit of turnover in recent years and all three of the commissioners are relatively new in their positions, adding a measure of

[20] Attachment SWS-RR-2 at 1.

[21] Attachment SWS-RR-8 at 1.

[22] Attachment SWS-RR-9 at 3, 4.

uncertainty. RRA accords Texas an Average/A3 ranking as it pertains to electric utilities under the PUC's purview."

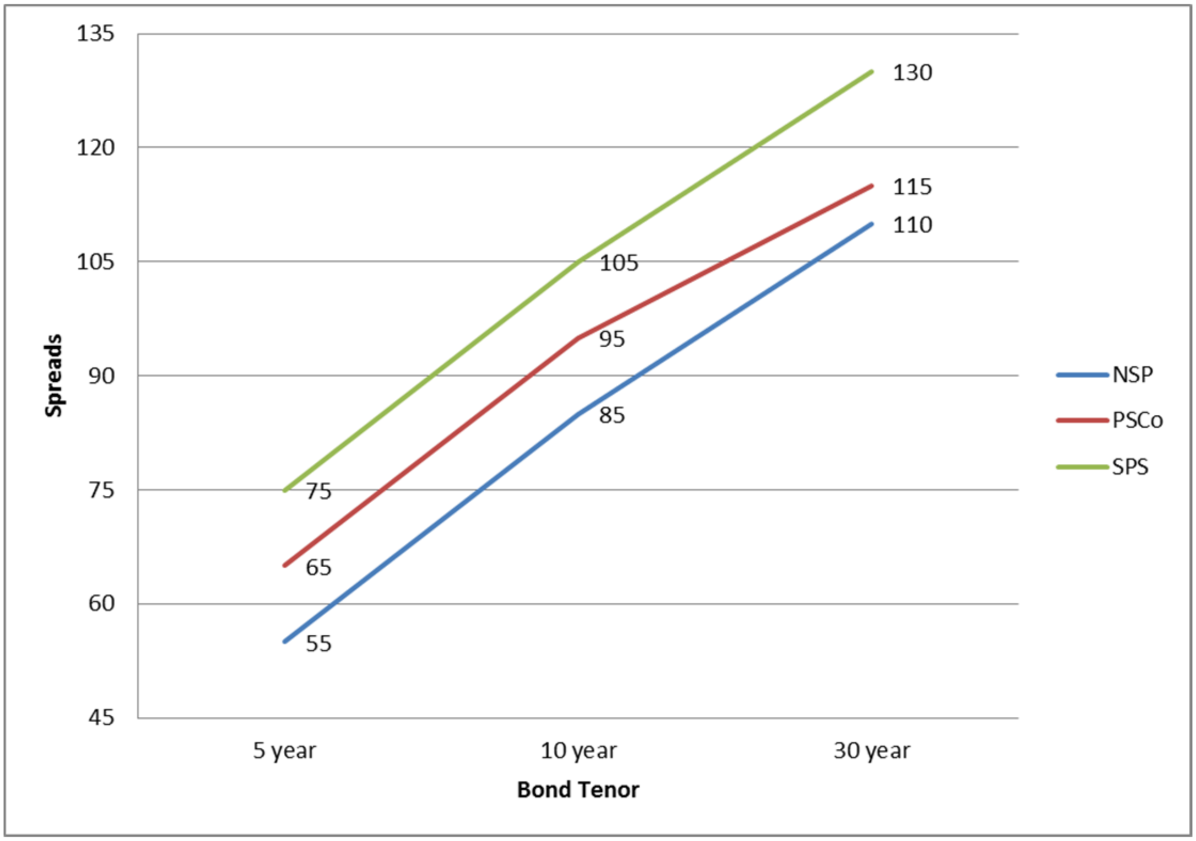
Q. Should the Commission be concerned with the rating agencies' analysis and ratings of SPS?

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 testimony. 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. 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. See Chart SWS-RR-3.

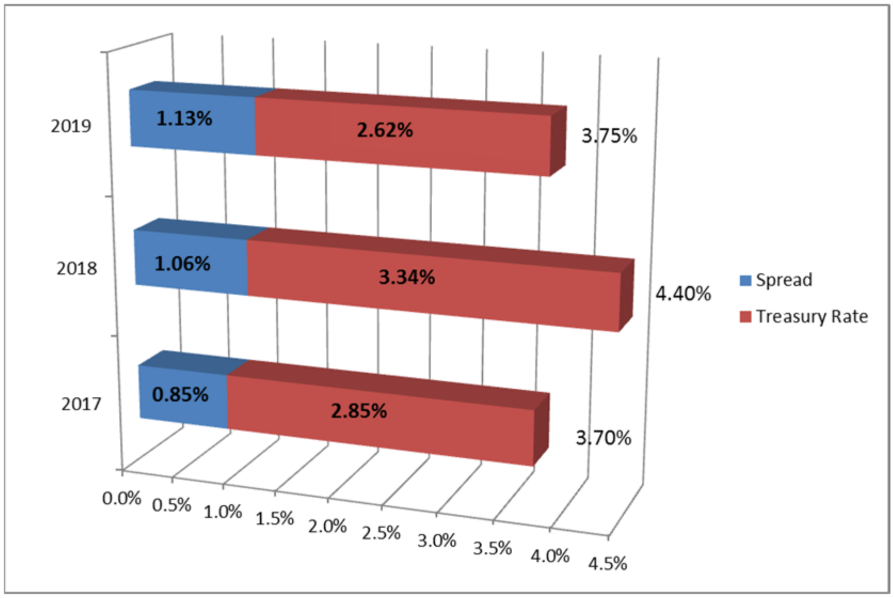
Chart SWS-RR-3: Indicative New Issue Spreads



Source: Scotiabank

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 long-term Treasury rates. As demonstrated in Chart SWS-RR-4, Treasury rates over the last 3 years have 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 investor perception that SPS’s risk has increased.

Chart SWS-RR-4: Components of SPS Coupons 2017-2019

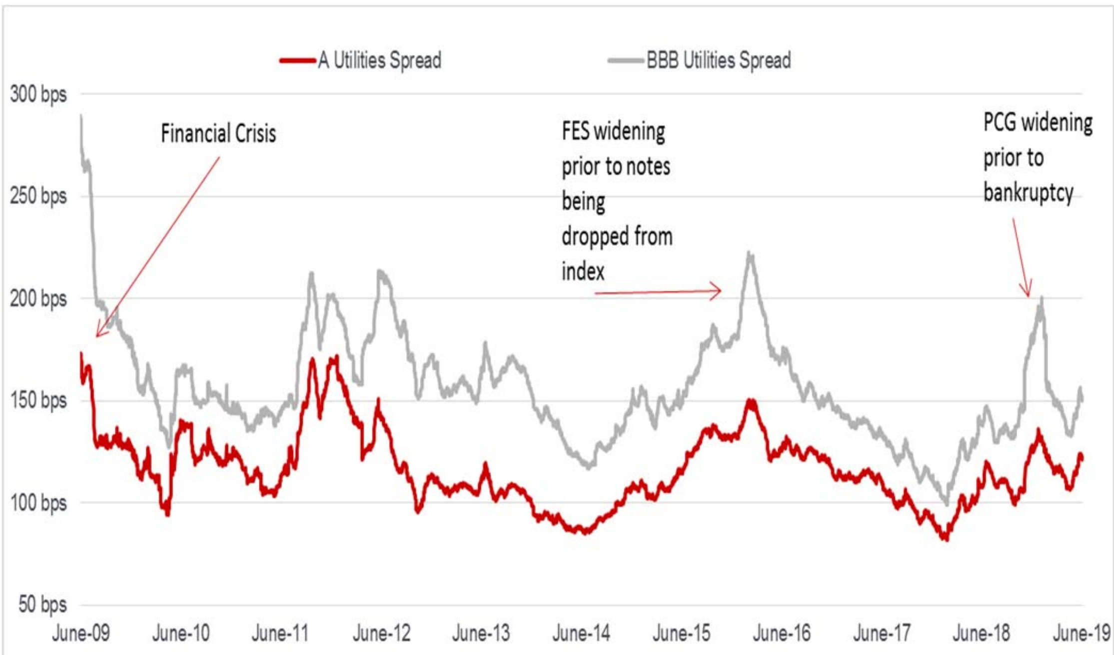


Moreover, economic downturns can have a material effect on a utility's access to capital, as evidenced by the financial crisis that began in 2008. During those periods of economic distress, the effects of credit ratings are magnified. In 2008, for example, utilities with A ratings generally had adequate 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?

Yes. Chart SWS-RR-5 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-RR-5: 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 its 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. <u>Maintaining and Strengthening SPS's Financial Integrity</u>

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

A. Yes. With a 54.65% regulated equity ratio: (1) the economic equity ratio including debt adjustments from S&P is 49.61%, 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-RR-9 and are outside of the range for A- rating, reflecting continued pressure on the current credit ratings.

Table SWS-RR-8: Economic Capital Structure

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	2,102.9	45.35%	Total Debt	2,126.3	41.64%	50.39%	Total Debt
Common Equity	2,534.5	54.65%	Total Equity	2,533.2	49.61%	49.61%	Total Equity
	$ 4,637.4	100.00%		$ 5,106.5	100.00%	100.00%	

Table SWS-RR-9: S&P Metrics at 54.65% 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-RR-10: Moody's Debt Metrics at 54.65% 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 agreements, 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 54.65% translates to an economic equity ratio of approximately 49.61% under S&P's methodology, which approximates what the rating agency would use to calculate credit metrics as part of the overall rating analysis. The regulated equity ratio understates true leverage because it excludes off balance sheet items as well as short-term debt. See Table SWS-RR-8.

Third, SPS faces regulatory risk as rating agencies and investors feel that SPS operates in 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 SPS'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 for the Test Year are shown in Table SWS-RR-11 below. The ROE is set at 10.35%, consistent with the proposed ROE in this case. The detailed schedules are included in Schedule K-1.

Table SWS-RR-11: SPS's Actual Test Year Capital Structure

		March 31, 2019	
	Ratio	**Rate**	**Wtd Cost**
Long-Term Debt	45.35%	4.40%	1.99%
Equity	54.65%	10.35%	5.66%
Total Cost			**7.65%**

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

A. SPS's proposed Updated Test Year WACC is 7.62% as shown below in Table SWS-RR-12. The Updated Test Year WACC is based on an ROE of 10.35%, a long-term debt cost of 4.33%, and a capital structure composed of 54.65% common equity and 45.35% long-term debt.

Table SWS-RR-12: SPS's Proposed Updated Test Year Capital Structure

Updated Test Year		**Forecast June 30, 2019**	
	Ratio	**Rate**	**Wtd Cost**
Long-Term Debt	45.35%	4.33%	1.96%
Equity	54.65%	10.35%	5.66%
Total Cost			**7.62%**

Q. What is SPS's recommended capital structure?

A. SPS recommends a capital structure consisting of 54.65% equity and 45.35% long-term debt. The use of SPS's Updated Test Year capital structure is reasonable in this case, in large part because it will help maintain SPS's current credit ratings.

Q. Does the fact that SPS operates in two separate jurisdictions create unique challenges for SPS?

A. Yes. Since SPS operates in two retail 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. SPS is requesting the adoption of a similar capital structure in its pending New Mexico rate case. In addition, SPS has requested that the New Mexico Commission lift the current equity cap of 55% in order to enable SPS to purse the stronger capital structure permitted by the [Texas] Commission.[23] This would allow SPS to potentially realize stronger credit metrics and lower costs to customers.

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

A. Yes.

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[23] The New Mexico cap is a hard cap on the equity ratio SPS can have, not a cap on the ratio to be used specifically for ratemaking purposes.

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 the SPS's equity of 54.65% as the regulated equity ratio mitigate additional downward pressure on its financial strength?

A. Yes. However, even at 54.65% equity, the downward pressure on SPS's credit metrics will continue. As I explained above, an equity ratio below 54.65% 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-/Baa2/BBB corporate ratings?

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 an A- corporate rating from S&P. SPS' CCRs at Baa2/BBB by Moody's and Fitch are the lowest in the Xcel family, lower than the Moody's and Fitch credit ratings for the Xcel Energy holding company at Baa1 and BBB+. A one notch downgrade by Moody's or Fitch of 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.[24]

[24] 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 during the Test Year?

A. SPS's embedded cost of long-term debt as of March 31, 2019 was 4.40%. The detailed calculation is shown in Schedule K-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 adjusted Long-Term Debt Balance 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 Test Year?

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 4.40% to 4.33%. 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.

Q. Does this conclude your direct testimony?

A. Yes, it does.

AFFIDAVIT

STATE OF MINNESOTA)
)
COUNTY OF HENNEPIN)

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

I am the witness identified in the preceding testimony. I have read the testimony and the accompanying attachment(s) and am familiar with the 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 30th day of July, 2019 by SARAH W. SOONG

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

Pamela C. Wilson

Notary Public, 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 Wharton 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 Manager of Corporate Finance from 2005 through 2010, followed by Director of Project Finance from 2010 through 2012 and finally as 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 Director and for Enron Corporation in Houston, Texas from 1997 through 2002 as Manager of Global Finance and Treasury.

I worked for ABN Amro Bank, Netherlands, Czech Republic from 1993 through 1995 as the Relationship Manager for 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	$1.5 \le x < 2.5$
Aa2	$2.5 \le x < 3.5$
Aa3	$3.5 \le x < 4.5$
A1	$4.5 \le x < 5.5$
A2	$5.5 \le x < 6.5$
A3	$6.5 \le x < 7.5$
Baa1	$7.5 \le x < 8.5$
Baa2	$8.5 \le x < 9.5$
Baa3	$9.5 \le x < 10.5$

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 up-streamed 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

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.

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
28 June 2019

Update

Rate this Research

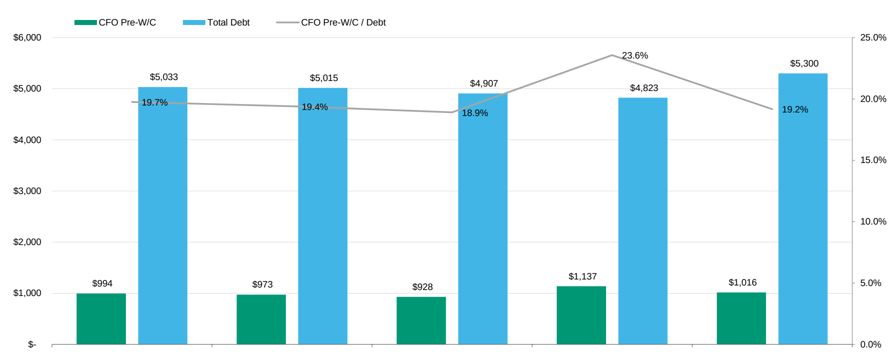
CenterPoint Energy Houston Electric, LLC

Update following outlook change to negative

Summary

CenterPoint Energy Houston Electric LLC's (CEHE) credit profile reflects its low business risk as a transmission and distribution (T&D) utility operating in Texas, where we view the regulatory environment to be generally constructive. CEHE operates within a geographically concentrated service territory but it is characterized by a strong local economy and above average customer growth. CEHE's operations are regulated by the Public Utility Commission of Texas (PUCT), which provides for timely recovery of prudently incurred costs and investments. Importantly, CEHE's credit profile incorporates our expectation of a continued supportive regulatory environment, particularly considering that CEHE is currently undergoing its first full rate case proceeding since 2011. In the first quarter of 2019, CEHE's parent, CenterPoint Energy Inc. (CNP, Baa2 stable) infused $590 million of equity into the utility. The negative outlook reflects the adverse cash flow implications of tax reform, along with higher debt incurred to fund its elevated capital investment plan, which are expected to weaken CEHE's key financial metrics more than we had projected when tax reform was passed. Going forward, we expect cash flow from operations before changes in working capital (CFO pre-WC) to debt will be in the 15% to 17% range, lower than historical levels of closer to 20% and weakly positioning CEHE from a financial metric standpoint. The outcome of the utility's pending rate case, expected by October, will be important in determining the future financial strength of the utility.

Exhibit 1
Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt ($MM)



Source: Moody's Financial Metrics

RATINGS

CenterPoint Energy Houston Electric, LLC

Domicile	Houston, Texas, United States
Long Term Rating	A3
Type	LT Issuer Rating
Outlook	Negative

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

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Credit strengths

» Credit supportive regulatory environment with timely recovery of capital through annual or semi-annual Transmission Cost of Service (TCOS) and Distribution Cost Recovery Factor (DCRF) filings

» Low business and carbon transition risk as a Texas T&D with no Provider of Last Resort Obligation (POLR)

» Experiencing above average growth in service territory

Credit challenges

» Tax reform will weaken financial metrics more than we had expected, exacerbated by the return of excess deferred income tax (EDIT) to customers.

» Higher debt to fund a robust capital plan will also pressure credit measures

» Increased parent leverage to fund Vectren acquisition

Rating outlook

CEHE's negative outlook reflects its declining credit measures largely due to tax reform and elevated capital spend and despite a financial policy that is targeting a 50% debt to capital ratio with recent capital contributions from the parent. Over the next few years, we see the ratio of CFO pre-WC to debt in the 15% to 17% range, weakly positioning CEHE from a financial metric standpoint, barring a supportive rate case outcome later this year.

Factors that could lead to an upgrade

Given the negative outlook and expected pressure on CEHE's credit measures, a ratings upgrade is unlikely over the next 12 to 18 months. However, the rating outlook could be stabilized if there is a supportive outcome of its pending rate case, or if the regulatory environment otherwise becomes more constructive leading to an improvement in CEHE's financial performance such that its CFO pre-WC to debt returns closer to historical levels. An upgrade could occur if CFO pre-W/C to debt rises above 22% on a sustainable basis.

Factors that could lead to a downgrade

CEHE's ratings could be downgraded if the utility's pending rate case or financial policies does not lead to a material improvement in projected financial metrics, including CFO pre-WC to debt below 18% on a sustained basis; there is a less supportive regulatory environment for transmission and distribution utilities in Texas overall, or there is a greater reliance on dividends from CEHE to support parent CNP's high leverage

Key indicators

Exhibit 2

CenterPoint Energy Houston Electric, LLC [1]

	Dec-15	Dec-16	Dec-17	Dec-18	LTM Mar-19
CFO Pre-W/C + Interest / Interest	5.5x	5.5x	5.5x	6.8x	6.1x
CFO Pre-W/C / Debt	19.7%	19.4%	18.9%	23.6%	19.2%
CFO Pre-W/C – Dividends / Debt	14.7%	16.7%	15.2%	19.2%	15.4%
Debt / Capitalization	58.9%	55.8%	60.0%	57.2%	55.7%

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

Profile

CenterPoint Energy Houston Electric, LLC is a rate-regulated electric transmission and distribution (T&D) utility serving approximately 2.5 million metered customers in the greater Houston, Texas area. CEHE is regulated by the Public Utility Commission of Texas (PUCT) and the cities in which it operates. CEHE is a core subsidiary of CenterPoint Energy, Inc. (CNP, Baa2 stable), a holding company that also owns regulated electric and natural gas utility subsidiaries and non-regulated businesses, primarily a joint venture interest in Enable Midstream Partners, LP (Enable, Baa3 stable) master limited partnership (MLP).

In addition to CEHE, CNP's other legacy subsidiary, CenterPoint Energy Resources Corp. (CERC, Baa1 positive), operates natural gas local distribution companies (LDCs) serving approximately 3.5 million customers across six states including Texas, Minnesota, Arkansas, Louisiana, Mississippi, and Oklahoma. CERC also owns CenterPoint Energy Services (CES, unrated), which is a natural gas marketing business that sells non-rate-regulated natural gas and related services to approximately 30,000 commercial, industrial and wholesale customers in 30 states.

On 1 February 2019, CNP completed its $8.5 billion acquisition of Vectren Corp. (Vectren, not rated), an energy holding company headquartered in Evansville, Indiana. Through the Vectren acquisition, CNP now also owns utility subsidiaries Indiana Gas Company (IGC, A2 negative), Southern Indiana Gas & Electric Company (SIGECO, A2 negative) and Vectren Energy Delivery of Ohio (VEDO, unrated).

Detailed credit considerations

Credit supportive regulatory environment

We view the Texas regulatory environment to be credit supportive, particularly for the state's electric T&D utilities. The regulatory framework provides several rate mechanisms and securitization policies for recovery of utility expenses such as bad debt, pension expenses and weather related restoration costs. Importantly, the framework also allows timely rate base recognition of investments in transmission and distribution assets in between rate cases through its Transmission Cost of Service (TCOS) and Distribution Cost Recovery Factor (DCRF) mechanisms, which is credit positive. In addition, CEHE has a long history of issuing securitization bonds. We view the savings associated with the lower financing costs as well as the ability to use securitization as a tool to recover costs related to large or unforeseen developments as a credit positive. The PUCT allows for CEHE to securitize storm restoration costs above $100 million.

First general rate case filing since 2010 adds a degree of regulatory risk

On 5 April 2019, CEHE filed its first full rate case request since 2010, seeking approval for a base rate revenue increase of approximately $161 million, including recovery on approximately $64 million in expenses related to Hurricane Harvey restoration efforts not currently reflected in rates. The filing was premised upon a 10.4% return on equity (ROE), 50% equity layer, a test year ending December 2018, and a 7.39% return on assets with a rate base valuation of $6.5 billion. In addition, CEHE also requested a prudency determination on all of its capital investments made since 2010 as well as the formation of a separate rider to refund approximately $97 million in unprotected Excess Deferred Income Tax (EDIT) to its customers over the next three years.

As of 13 June 2019, four interveners had provided testimony supporting a lower ROE and lower equity layer than CEHE is seeking. Additionally, on 12 June 2019, the PUCT staff weighed in on the matter, recommending a 9.45% ROE and a 40% equity layer, significantly lower than the company had requested. A final rate case outcome that provides CEHE with an ROE materially below its current 10% ROE and an equity layer lower than its current 45% may further pressure credit measures. Some parties, including PUCT staff also recommend ring-fencing provisions on CEHE including a limitation on dividends paid. The intervenors include Texas' Office of Public Utility Counsel, the City of Houston, the Texas Coast Utilities Coalition and the Texas Industrial Energy Consumers.

We would view ring-fencing as currently credit neutral for CEHE because it would largely take effect only when CEHE's parent or sister companies experience credit stress and would limit the ability to substantially consolidate CEHE in the event of a bankruptcy of its parent or CEHE's sister companies. However, only in the event of credit stress or a bankruptcy of CNP or CEHE's sister companies, ring-fencing would be credit positive for CEHE. Ring-fencing provisions also include a limitation on dividends to the parent that would also be credit neutral for CEHE because we do not forecast the utility's dividend levels to be greater than net income over the next few years, and dividends paid are typically governed by a utility's regulatory capital structure. We believe other ring-fencing provisions proposed by the PUCT staff, which include separation of assets and liquidity, are somewhat common management practices in the sector.

CEHE's last general rate case was finalized in 2011, in which the PUCT authorized a 10.0% ROE and 45% equity layer. Since its last rate case proceeding, CEHE has had an increase of around 400,000 customers and has invested over $6 billion in its T&D system.

Historically stable financial metrics weakening considerably due to tax reform and higher debt

CEHE has historically exhibited a stable financial performance. For the last twelve months (LTM) ending 31 March 2019, CEHE's adjusted interest coverage and CFO pre-WC to debt ratios were 6.1x and 19.2%, respectively. As of 31 March 2019, CEHE's adjusted three-year average ratio of CFO pre-WC to debt was 19.2%, reflecting the stable nature of its cash flows and the company's fiscal policies. Going forward, we expect CEHE's key credit metrics to weaken such that the ratio of CFO pre-W/C will be in the 15% to 17% range, reflecting the impacts of the Tax Cuts and Jobs Act (TCJA) and including the effects of securitization. At 31 March 2019, CEHE's adjusted debt to total capital ratio was 55.7%.

In the presentation of securitization debt in our published financial ratios for CEHE, we follow the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP). We view securitization debt of utilities as on-credit debt as it is the recovery of expenses and capital spent on utility plant to restore service. In addition, because the rates associated with it reduces the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers while accelerating capital recovery for the utility. Excluding the securitized debt outstanding and associated revenues (debt amortization and interest) would result in a lower and more volatile credit measures, especially in years when securitization debt matures. The amortization of securitized debt principal also will have an impact on CEHE's depreciation and amortization levels, impacting cash flow.

While CEHE's securitized debt is on balance sheet, our credit analysis also considers the impact of its financial ratios excluding securitization debt and related revenues to ensure that the benefits of securitization are considered.

Exhibit 3
CFO pre-W/C to debt impact from securitization

	2013	2014	2015	2016	2017	2018
(CFO Pre-W/C) / Debt	**16.4%**	**18.2%**	**19.7%**	**19.4%**	**18.9%**	**23.6%**
Securitization:						
Amortization	-$383	-$441	-$368	-$456	-$330	-$532
Debt outstanding	$3,400	$3,037	$2,667	$2,278	$1,868	$1,435
CFO Pre-W/C (excluding Securitization)	$501	$553	$626	$517	$598	$605
Total Debt (excluding Securitization)	$2,003	$2,423	$2,366	$2,737	$3,039	$3,388
(CFO Pre-W/C) / Debt (excluding Securitization)	**25.0%**	**22.8%**	**26.5%**	**18.9%**	**19.7%**	**17.9%**

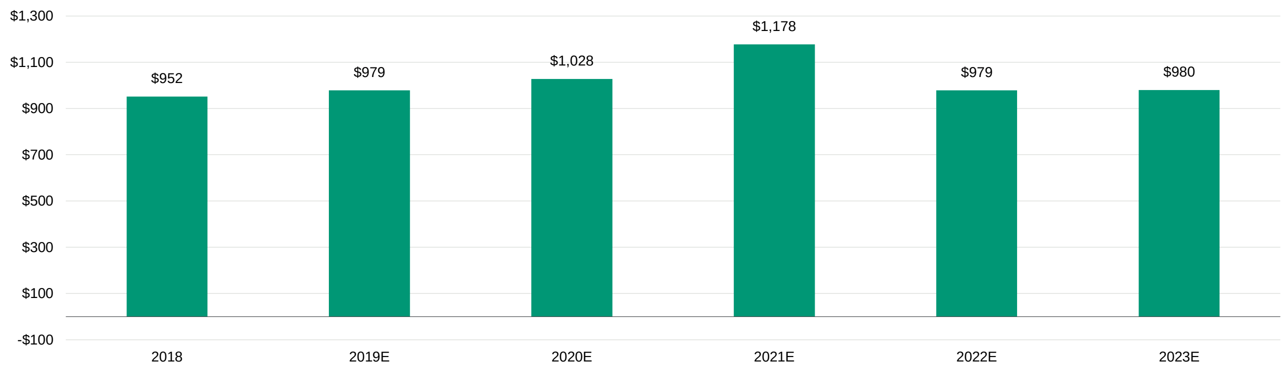
Source: Moody's Financial Metrics, company filings

As the securitization debt amortizes, the impact on cash flow measures becomes less meaningful. Looking forward, we expect CEHE's CFO pre-WC to debt ratio to be 50bps to 150bps lower than our published ratios if securitization debt is excluded.

Robust capital investment program also pressuring metrics

During the 2016 to 2018 period, CEHE averaged approximately $886 million in annual capital expenditures (capex), which is considerably higher than historical amounts. We expect CEHE's capital investment plan to remain robust going forward, totaling over $5 billion from 2019 through 2023. At the end of 2018, CEHE's rate base was over $6 billion and we anticipate that will increase to over $9 billion by 2023.

Exhibit 4
CEHE's Capital Investment Plan
$ in millions



Source: Company filings

In April 2017, CEHE submitted a transmission project proposal to the Electric Reliability Council of Texas (ERCOT), which operates the electric grid in Texas, to address the continued growth from the petrochemical industry in the Freeport, Texas area. ERCOT approved the project in December 2017 and the Certificate of Convenience and Necessity (CCN) filing that is pending with the PUCT includes a cost estimate range of $482 to $695 million with a decision expected later in 2019.

Geographically concentrated service territory, experiencing above average growth

CEHE's operations are concentrated in the Texas Gulf Coast region including the Houston area, where unpredictable energy markets can lead to volatility in its economy. According to Moody's Economy.com, the Houston area economy is growing at an above-average pace with elevated job growth and demographics. This rebound follows the collapse in oil prices just a few years ago and more recent gains in manufacturing and residential reconstruction amid income growth and Hurricane Harvey rebuilding. Houston's port is also one the largest in the U.S. and boasts the largest U.S. export market driven by increasing energy exports.

Low business and carbon transition risk as a Texas T&D

Moody's generally views regulated utilities as having lower business risk than unregulated businesses, as regulated rates produce more predictable and stable earnings and cash flows over the long term. CEHE's business and operating risk profile is also low considering that there are no commodity price and operating risks related to owning electric generation. Unlike most T&D utilities in the US, Texas T&D utilities are not obligated to be the Provider of Last Resort (POLR), in which case they would be at risk of having to procure power for customers who do not have a retail energy provider. As a result, Moody's employs the Regulated Electric and Gas methodology utilizing the Low Business Risk financial metric grid.

CEHE has low carbon transition risk within the regulated electric and gas utility sector as a transmission and distribution utility but it is exposed to environmental risk, most notably from the increasing severity of major hurricanes in the Gulf of Mexico which can have destructive impacts on Houston and the surrounding service territory. Nevertheless, the financial risk associated with such storms is mitigated by the PUCT which allows Texas utilities to securitize prudently incurred costs to recover and restore service from storms. Our carbon transition report for utilities can be found at "Regulated Utilities: Prudent regulation key to mitigating, capturing opportunities of decarbonization"(2 Nov 2017) and "Moody's cross-sector methodology for assessing General Principles for Assessing Environmental, Social and Governance Risks."

Liquidity analysis

We expect CEHE to maintain a good liquidity profile over the next 12-18 months.

For the LTM ending 31 March 2019, CEHE reported approximately $1.0 billion of cash from operations, invested $950 million in capital expenditures, and up-streamed $201 million in dividend payments to parent CNP, resulting in negative free cash flow of approximately $150 million.

CEHE has a $300 million credit facility which expires in March 2022 and as of 25 April 2019, the only amount utilized was $4 million in outstanding letters of credit. The credit agreement has a sole financial covenant requiring a maximum debt to capital (excluding securitization debt) ratio of 65%, which could temporarily increase to 70% if CEHE experiences damage from a natural disaster in its service territory. CEHE also participates in a money pool with access to an additional $300 million. As of 31 March 2019, CEHE reported a debt to capital ratio of 49.9%.

CEHE has no long-term debt maturities until 2021 except for principal amortization of its securitization bonds, accounting for approximately $458 million in 2019 and $442 million in 2020-2021.

Rating methodology and scorecard factors

Exhibit 5

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 3/31/2019		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%) [4]				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	5.8x	A	5x - 5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	19.2%	A	15% - 17%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	15.6%	A	11% - 13%	Baa
d) Debt / Capitalization (3 Year Avg)	57.4%	Baa	55% - 60%	Baa
Rating:				
Scorecard-indicated Outcome Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching				
a) Scorecard-indicated Outcome		A3		A3
b) Actual Rating Assigned		A3		A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2019(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
[4] Low business risk grid for financial strength.
Source: Moody's Financial Metrics

Appendix

Exhibit 6
CEHE sources & uses free cash flow analysis
($ in millions)

CenterPoint Energy Houston Electric, LLC	FY 2015	FY 2016	FY 2017	FY 2018	LTM 3/19
Sources:					
CFO	895	1,110	905	1,115	1,001
Debt Issued	200	600	298	398	696
Equity Issued	-	-	-	-	-
Other Financing	458	(497)	263	(148)	(892)
Capital Contribution from Parent	-	374	-	200	790
Total Sources:	**1,553**	**1,587**	**1,466**	**1,565**	**1,595**
Uses:					
Capital Expenditures	(929)	(862)	(875)	(922)	(950)
Dividends	(252)	(135)	(180)	(209)	(201)
Debt Repayment	(372)	(590)	(411)	(434)	(444)
Acquisitions	-	-	-	-	-
Total Uses:	**(1,553)**	**(1,587)**	**(1,466)**	**(1,565)**	**(1,595)**

FCF	FY 2015	FY 2016	FY 2017	FY 2018	LTM 3/19
CFO	895	1,110	905	1,115	1,001
Capex	(929)	(862)	(875)	(922)	(950)
Dividends	(252)	(135)	(180)	(209)	(201)
Acquisitions	-	-	-	-	-
Free Cash Flow (FCF)	**(286)**	**113**	**(150)**	**(16)**	**(150)**
Funded:					
Equity Issued	-	374	-	200	790
Debt issued	200	600	298	398	696
Other Financing	458	(497)	263	(148)	(892)
% Funded:					
Equity Issued	0.0%	78.4%	0.0%	44.4%	133.0%
Debt issued	100.0%	21.6%	100.0%	55.6%	-33.0%
% of Funded FCF	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Other financing is predominantly short-term debt
Source: Moody's Investors Service

Exhibit 7
Cash Flow and Credit Metrics [1]

CF Metrics	Dec-15	Dec-16	Dec-17	Dec-18	LTM Mar-19
As Adjusted					
FFO	999	1,094	1,073	1,227	1,149
+/- Other	(5)	(121)	(145)	(90)	(133)
CFO Pre-WC	994	973	928	1,137	1,016
+/- ΔWC	(99)	137	(22)	(21)	(14)
CFO	895	1,110	906	1,116	1,002
- Div	252	135	180	209	201
- Capex	929	862	876	923	951
FCF	(286)	113	(150)	(16)	(150)
(CFO Pre-W/C) / Debt	19.7%	19.4%	18.9%	23.6%	19.2%
(CFO Pre-W/C - Dividends) / Debt	14.7%	16.7%	15.2%	19.2%	15.4%
FFO / Debt	19.8%	21.8%	21.9%	25.4%	21.7%
RCF / Debt	14.8%	19.1%	18.2%	21.1%	17.9%
Revenue	2,846	3,059	2,998	3,234	3,165
Cost of Good Sold	1,311	1,363	1,401	1,451	1,477
Interest Expense	223	217	205	197	200
Net Income	261	276	433	336	311
Total Assets	10,025	10,211	10,296	10,511	11,420
Total Liabilities	8,542	8,244	8,077	7,932	8,214
Total Equity	1,483	1,967	2,219	2,579	3,206

[1]All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 8
Peer Comparison Table [1]

	CenterPoint Energy Houston Electric, LLC A3 Stable			Oncor Electric Delivery Company LLC A2 Stable [2]			AEP Texas Inc. Baa1 Stable			Texas-New Mexico Power Company A3 Stable		
	FYE	FYE	LTM	FYE	FYE	LTM	FYE	FYE	LTM	FYE	FYE	LTM
(in US millions)	Dec-17	Dec-18	Mar-19	Dec-17	Dec-18	Mar-19	Dec-17	Dec-18	Mar-19	Dec-17	Dec-18	Mar-19
Revenue	2,998	3,234	3,165	3,958	4,101	4,127	1,538	1,595	1,614	341	345	343
CFO Pre-W/C	928	1,137	1,016	1,695	1,487	1,342	677	651	645	110	109	106
Total Debt	4,907	4,823	5,300	8,109	8,314	8,618	3,764	4,236	4,159	500	616	818
CFO Pre-W/C / Debt	18.9%	23.6%	19.2%	20.9%	17.9%	15.6%	18.0%	15.4%	15.5%	22.0%	17.6%	12.9%
CFO Pre-W/C – Dividends / Debt	15.2%	19.2%	15.4%	18.0%	15.4%	12.3%	18.0%	15.4%	15.5%	13.2%	10.8%	6.6%
Debt / Capitalization	60.0%	57.2%	55.7%	46.4%	45.3%	45.9%	55.2%	55.1%	53.1%	39.6%	43.2%	50.5%

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
[2] Senior secured rating.
Source: Moody's Financial Metrics

Ratings

Exhibit 9

Category	Moody's Rating
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	
Outlook	Negative
Issuer Rating	A3
Senior Secured	A1
Sr Unsec Bank Credit Facility	A3
PARENT: CENTERPOINT ENERGY, INC.	
Outlook	Stable
Issuer Rating	Baa2
Bkd Senior Secured	A1
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Subordinate	Baa3
Pref. Stock	Ba1
Commercial Paper	P-2
ST Issuer Rating	P-2
RELIANT ENERGY HL&P	
Outlook	No Outlook
Bkd First Mortgage Bonds	A1

Source: Moody's Investors Service

REPORT NUMBER 1180512

Southwestern Public Service Company

Credit Rating Descriptions

DESCRIPTION OF BOND RATINGS

Categories	Moody's (1)	Standard & Poor's/Fitc	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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Criteria | Corporates | General:

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	Review — No Action Oct. 26, 2018
Short-Term IDR	F2		Under Criteria Observation May 2, 2019
Senior Secured Debt	A–		Review — No Action Oct. 26, 2018
Senior Unsecured Debt	BBB+		Review — No Action Oct. 26, 2018
CP	F2		Under Criteria Observation May 2, 2019

Click here for full list of ratings

Financial Summary

(USD Mil.)	Dec 2015	Dec 2016	Dec 2017	Dec 2018
Gross Revenue	1,787	1,851	1,918	1,933
Operating EBITDAR	433	477	498	530
Cash Flow from Operations	315	389	470	446
Capital Intensity (Capex/Revenue, %)	33.1	27.7	29.2	52.8
Total Adjusted Debt with Equity Credit	1,612	1,748	1,906	2,255
FFO Fixed-Charge Coverage (x)	5.0	5.5	5.6	5.8
FFO-Adjusted Leverage (x)	3.5	3.3	3.6	4.4
Total Adjusted Debt/Operating EBITDAR (x)	3.7	3.7	3.8	4.3

Source: Fitch Ratings, 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. 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. In addition, SPS appealed multiple NMPRC decisions to the New Mexico Supreme Court in recent years.

Supportive rate design mechanisms in Texas and New Mexico 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 2019 Electric Rate Case: SPS filed an electric rate case with the NMPRC on July 1, 2019, seeking a $51 million increase in retail electric base rates. The request is based on a historic test year ended March 31, 2019, a 10.35% ROE and a 54.77% equity ratio. The request would result in an approximately $26 million, or 5.7%, net revenue increase to New Mexico customers, due to offsetting fuel cost reductions and wind energy production tax credits that are being credited to customers through the fuel clause. SPS is requesting new rates effective July 31, 2019, although an NMPRC decision and implementation of final rates is not expected until the second or third quarter of 2020.

New Mexico 2017 Electric Rate Case: SPS and the NMPRC settled SPS's appeal to the New Mexico Supreme Court regarding the NMPRC's original 2017 electric rate order. Fitch views the settlement agreement to be more balanced than the initial rate order. The settlement resulted in a revised order that increased the authorized ROE to 9.56% from 9.1% and the equity ratio to 53.97% from 51%. The order also eliminated a $10.2 million refund of retroactive benefits from the Tax Cuts and Jobs Act. New rates became effective March 11, 2019.

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, 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**.**

Customer savings related to federal tax reform were incorporated in SPS's rate case settlement agreement in June 2018 in Texas. The settlement reflected no change in customer rates or refunds and an increase in the equity ratio to 57% to help offset the negative effects of federal tax reform on SPS's credit metrics.

Large Capex Plan: SPS has a large capex plan. 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. Management expects capex to total more than $3.5 billion over 2019–2023, with peak-year spending exceeding $1.1 billion in 2019.

Parent/Subsidiary Linkage: Fitch uses a bottom-up approach in determining the ratings on Xcel Energy, Inc. (BBB+/Stable) and its utility subsidiaries. The linkage follows a strong parent/weak subsidiary approach for SPS and a weak parent/strong subsidiary approach for SPS's 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). Fitch considers SPS to be weaker than Xcel primarily due to the challenging regulatory environment in New Mexico and Texas. Fitch considers PSCo, NSP-Minnesota and NSP-Wisconsin to be stronger than Xcel due to the utilities' low-risk operations and exposure to constructive regulatory jurisdictions.

There is moderate linkage between the long-term IDR of Xcel and that of the utility subsidiaries. The utilities have good access to debt capital markets. However, they lack strong ring-fencing provisions and participate in a money pool, which would suggest closer linkage. Fitch could allow for up to a two-notch difference in the long-term IDRs of Xcel and its utility subsidiaries.

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: PSCo, NSP-Minnesota and NSP-Wisconsin. SPS and Public Service Company of Oklahoma (PSO, BBB+/Stable) have similar credit profiles. Both companies have large capex plans, but benefit from supportive parent companies. Financial metrics are similar and are adequate for the ratings; adjusted debt/EBITDAR and FFO-adjusted leverage at SPS were 4.3x and 4.4x, respectively, in 2018, compared with 4.6x and 4.0x at PSO. The difference in the ratings is largely driven by the more challenging regulatory environment faced by SPS.
Parent/Subsidiary Linkage	Fitch uses a bottom-up approach in determining the ratings on Xcel and its utility subsidiaries. The linkage follows a strong parent/weak subsidiary approach for SPS and a weak parent/strong subsidiary approach for SPS's sister utilities: PSCo, NSP-Minnesota and NSP-Wisconsin. Fitch considers SPS to be weaker than Xcel primarily due to the challenging regulatory environment in New Mexico and Texas. Fitch considers PSCo, NSP-Minnesota and NSP-Wisconsin to be stronger than Xcel due to the utilities' low-risk operations and exposure to constructive regulatory jurisdictions. There is moderate linkage between the IDR of Xcel and that of the utility subsidiaries. The utilities have good access to debt capital markets. However, they lack strong ring-fencing provisions and participate in a money pool, which would suggest closer linkage. Fitch could allow for up to a two-notch difference in the IDRs of Xcel and 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 Ratings.

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+
Northern States Power Company-Minnesota	A-/Sta	aa	a-	a-	a-	bbb+	bbb+	bbb+	a-	a-
Northern States Power Company-Wisconsin	A-/Sta	aa	a-	a	a-	bbb+	bbb+	bbb+	a-	a-
Public Service Company of Colorado	A-/Sta	aa	a-	a-	a-	bbb+	bbb+	a-	a-	a-
Oklahoma Gas & Electric Co.	A-/Sta	aa	bbb+	bbb	bbb+	bbb	a-	a-	a-	a-
Public Service Company of Oklahoma	BBB+/Sta	aa	a-	bbb+	a-	bbb+	bbb+	bbb	bbb+	bbb+
Southwestern Electric Power Co.	BBB/Sta	aa	a-	bbb	bbb+	bbb	bbb+	bbb	bbb-	bbb

Source: Fitch Ratings. 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 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 each of their revolving credit facilities (RCFs), all of which expire in June 2024. RCF borrowing limits for each entity are $1.25 billion for Xcel, $700 million for PSCo, $500 million for NSP-Minnesota, $500 million for SPS and $150 million for NSP-Wisconsin. Xcel and its utility subsidiaries had an aggregate $752 million of CP outstanding and $51 million of LCs issued as of March 31, 2019.

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 and NSP-Minnesota and $100 million for SPS. NSP-Wisconsin is not a participant in the money pool.

Xcel and its utility subsidiaries require modest cash on hand. Xcel had $94 million of unrestricted cash and cash equivalents at March 31, 2019.

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

Liquidity and Long-Term Debt Maturities

Scheduled Long-Term Debt Maturities at Dec. 31, 2018	**(USD Mil.)**
2019	0
2020	0
2021	0
2022	0
2023	0
Thereafter	2,150
Total Long-Term Debt	**2,150**

Source: Fitch Ratings, Fitch Solutions, Southwestern Public Service Company.

Liquidity Summary at March 31, 2019	**(USD Mil.)**
Unrestricted Cash and Cash Equivalents	1
Committed Bank Facilities	400
Money Pool Borrowing Limit	100
Short-Term Borrowings	175
LCs Outstanding	2
Availability Under Bank Facilities and Money Pool	323
Total Liquidity	**324**

Source: Fitch Ratings, Fitch Solutions, Southwestern Public Service Company.

Key Assumptions

Fitch's Key Assumptions Within Our Rating Case for SPS Include

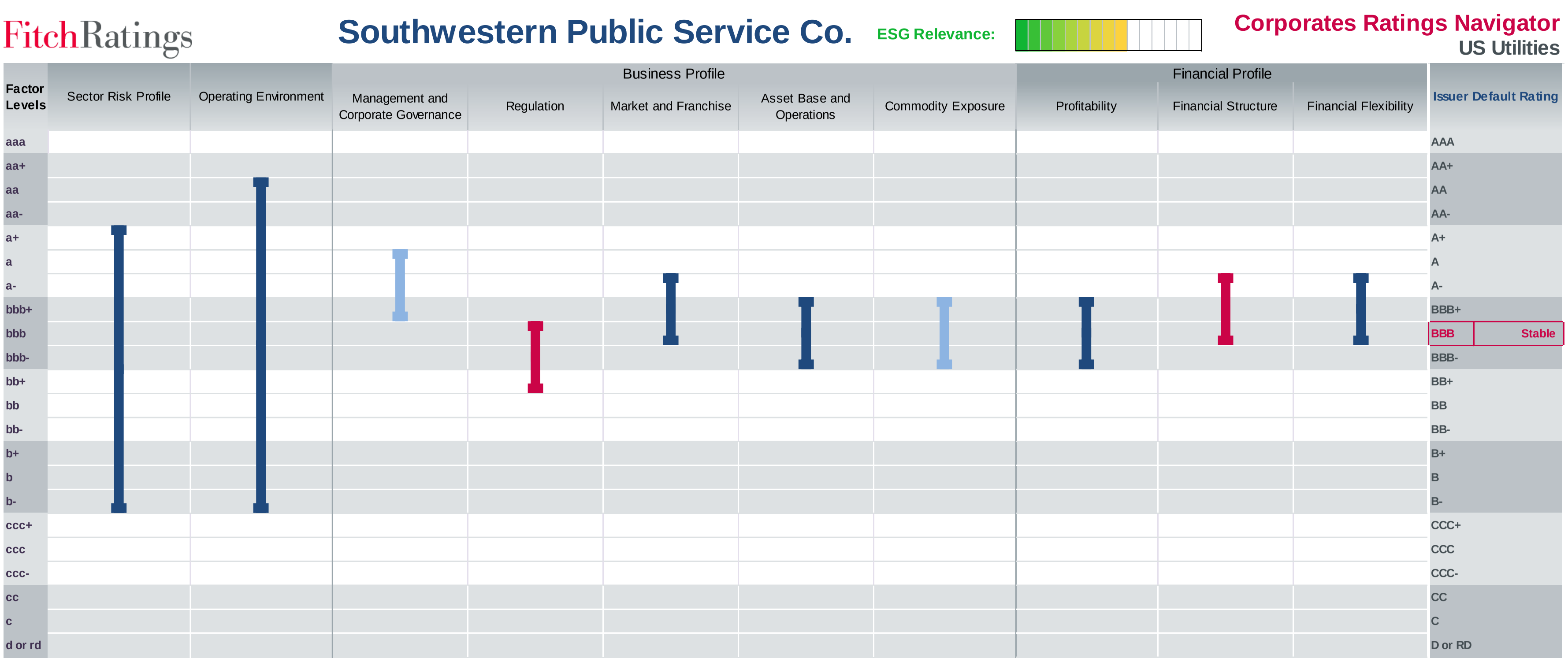
- Capex of $3.5 billion over 2019–2023, including nearly $1.3 billion on electric transmission over 2019–2023 and nearly $1.0 billion on renewable energy over 2019–2020;
- Rate case outcomes consistent with historical rate orders.

Financial Data

(USD Mil.)	Historical			
	Dec 2015	Dec 2016	Dec 2017	Dec 2018
Summary Income Statement				
Gross Revenue	1,787	1,851	1,918	1,933
Revenue Growth (%)	-7.7	3.6	3.6	0.8
Operating EBITDA (Before Income from Associates)	427	471	491	522
Operating EBITDA Margin (%)	23.9	25.4	25.6	27.0
Operating EBITDAR	433	477	498	530
Operating EBITDAR Margin (%)	24.2	25.8	25.9	27.4
Operating EBIT	274	308	297	312
Operating EBIT Margin (%)	15.3	16.6	15.5	16.1
Gross Interest Expense	-85	-89	-86	-85
Pretax Income (Including Associate Income/Loss)	202	235	228	252
Summary Balance Sheet				
Readily Available Cash and Equivalents	1	1	11	44
Total Debt with Equity Credit	1,565	1,700	1,850	2,192
Total Adjusted Debt with Equity Credit	1,612	1,748	1,906	2,255
Net Debt	1,564	1,699	1,839	2,148
Summary Cash Flow Statement				
Operating EBITDA	427	471	491	522
Cash Interest Paid	-85	-89	-86	-80
Cash Tax	-24	61	42	-11
Dividends Received Less Dividends Paid to Minorities (Inflow/(Out)flow)	0	0	0	0
Other Items Before FFO	50	-14	-10	-8
Funds Flow from Operations	368	429	435	423
FFO Margin (%)	20.6	23.2	22.7	21.9
Change in Working Capital	-53	-40	35	24
Cash Flow from Operations (Fitch Defined)	315	389	470	446
Total Non-Operating/Nonrecurring Cash Flow	0	0	0	0
Capex	-592	-513	-560	-1,021
Capital Intensity (Capex/Revenue) %	33.1	27.7	29.2	52.8
Common Dividends	-101	-85	-109	-131
FCF	-378	-209	-198	-706
Net Acquisitions and Divestitures	0	0	0	0
Other Investing and Financing Cash Flow Items	3	13	-56	65
Net Debt Proceeds	160	130	121	337
Net Equity Proceeds	215	66	144	337
Total Change in Cash	0	0	10	33
Calculations for Forecast Publication				
Capex, Dividends, Acquisitions and Other Items Before FCF	-693	-598	-669	-1,152
FCF After Acquisitions and Divestitures	-378	-209	-198	-706
FCF Margin (After Net Acquisitions) (%)	-21.2	-11.3	-10.3	-36.5
Coverage Ratios				
FFO Interest Coverage (x)	5.3	5.8	6.0	6.3
FFO Fixed-Charge Coverage (x)	5.0	5.5	5.6	5.8
Operating EBITDAR/Interest Paid + Rents (x)	4.8	5.0	5.3	6.0
Operating EBITDA/Interest Paid (x)	5.0	5.3	5.7	6.5
Leverage Ratios				
Total Adjusted Debt/Operating EBITDAR (x)	3.7	3.7	3.8	4.3
Total Adjusted Net Debt/Operating EBITDAR (x)	3.7	3.7	3.8	4.2
Total Debt with Equity Credit/Operating EBITDA (x)	3.7	3.6	3.8	4.2
FFO-Adjusted Leverage (x)	3.5	3.3	3.6	4.4
FFO-Adjusted Net Leverage (x)	3.5	3.3	3.6	4.3

Source: Fitch Ratings, Fitch Solutions.

Ratings Navigator



FitchRatings

Southwestern Public Service Co.

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+			

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			

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.

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.

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+			

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+			

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 Structure

a	Lease Adjusted FFO Gross Leverage	bbb	5.0x
a-	Total Adjusted Debt/Operating EBITDAR	bbb	3.75x
bbb+			
bbb			
bbb-			

Financial Flexibility

a	Financial Discipline	a	Clear commitment to maintain a conservative policy with only modest deviations allowed.
a-	Liquidity	bbb	One-year liquidity ratio above 1.25x. Well-spread maturity schedule of debt but funding may be less diversified.
bbb+	FFO Fixed Charge Cover	a	5.0x
bbb			
bbb-			

Credit-Relevant ESG Derivation

Southwestern Public Service Co. has 12 ESG potential rating drivers

- Emissions from operations
- Fuel use to generate energy and serve load
- Impact of waste from operations
- Plants' and networks' exposure to extreme weather
- Product affordability and access
- Quality and safety of products and services; data security

Showing top 6 issues

			Overall ESG
key driver	0	issues	5
driver	0	issues	4
potential driver	12	issues	3
not a rating driver	2	issues	2
	0	issues	1

For further details on Credit-Relevant ESG scoring, see page 3.

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 2.2.0.0

FitchRatings

Southwestern Public Service Co.

Corporates Ratings Navigator
US Utilities

Credit-Relevant ESG Derivation

Southwestern Public Service Co. has 12 ESG potential rating drivers

- Southwestern Public Service Co. has exposure to emissions regulatory risk but this has very low impact on the rating.
- Southwestern Public Service Co. has exposure to energy productivity risk but this has very low impact on the rating.
- Southwestern Public Service Co. has exposure to waste & impact management risk but this has very low impact on the rating.
- Southwestern Public Service Co. has exposure to extreme weather events but this has very low impact on the rating.
- Southwestern Public Service Co. has exposure to access/affordability risk but this has very low impact on the rating.
- Southwestern Public Service Co. has exposure to customer accountability risk but this has very low impact on the rating.

Showing top 6 issues

			Overall ESG Scale
key driver	0	issues	5
driver	0	issues	4
potential driver	12	issues	3
not a rating driver	2	issues	2
	0	issues	1

Environmental (E)

General Issues	E Score	Sector-Specific Issues	Reference
GHG Emissions & Air Quality	3	Emissions from operations	Asset Base and Operations; Commodity Exposure; Regulation; Profitability
Energy Management	3	Fuel use to generate energy and serve load	Asset Base and Operations; Commodity Exposure; Profitability
Water & Wastewater Management	2	Water used by hydro plants or by other generation plants, also effluent management	Asset Base and Operations; Regulation; Profitability
Waste & Hazardous Materials Management; Ecological Impacts	3	Impact of waste from operations	Asset Base and Operations; Regulation; Profitability
Exposure to Environmental Impacts	3	Plants' and networks' exposure to extreme weather	Asset Base and Operations; Regulation; Profitability

E Scale: 5, 4, 3, 2, 1

Social (S)

General Issues	S Score	Sector-Specific Issues	Reference
Human Rights, Community Relations, Access & Affordability	3	Product affordability and access	Asset Base and Operations; Regulation; Profitability; Financial Structure
Customer Welfare - Fair Messaging, Privacy & Data Security	3	Quality and safety of products and services; data security	Regulation; Profitability
Labor Relations & Practices	3	Impact of labor negotiations and employee (dis)satisfaction	Asset Base and Operations; Profitability
Employee Wellbeing	2	Worker safety and accident prevention	Profitability; Asset Base and Operations
Exposure to Social Impacts	3	Social resistance to major projects that leads to delays and cost increases	Asset Base and Operations; Profitability

S Scale: 5, 4, 3, 2, 1

Governance (G)

General Issues	G Score	Sector-Specific Issues	Reference
Management Strategy	3	Strategy development and implementation	Management and Corporate Governance
Governance Structure	3	Board independence and effectiveness; ownership concentration	Management and Corporate Governance
Group Structure	3	Complexity, transparency and related-party transactions	Management and Corporate Governance
Financial Transparency	3	Quality and timing of financial disclosure	Management and Corporate Governance

G Scale: 5, 4, 3, 2, 1

How to Read This Page
ESG scores range from 1 to 5 based on a 15-level color gradation. Red (5) is most relevant and green (1) is least relevant.

The Environmental (E), Social (S) and Governance (G) tables break out the individual components of the scale. The left-hand box shows the aggregate E, S, or G score. General Issues are relevant across all markets with Sector-Specific Issues unique to a particular industry group. Scores are assigned to each sector-specific issue. These scores signify the credit-relevance of the sector-specific issues to the issuing entity's overall credit rating. The Reference box highlights the factor(s) within which the corresponding ESG issues are captured in Fitch's credit analysis.

The Credit-Relevant ESG Derivation table shows the overall ESG score. This score signifies the credit relevance of combined E, S and G issues to the entity's credit rating. The three columns to the left of the overall ESG score summarize the issuing entity's sub-component ESG scores. The box on the far left identifies the [number of] general ESG issues that are drivers or potential drivers of the issuing entity's credit rating (corresponding with scores of 3, 4 or 5) and provides a brief explanation for the score.

Classification of ESG issues has been developed from Fitch's sector and sub-sector ratings criteria and the General Issues and the Sector-Specific Issues have been informed with SASB's Materiality Map.

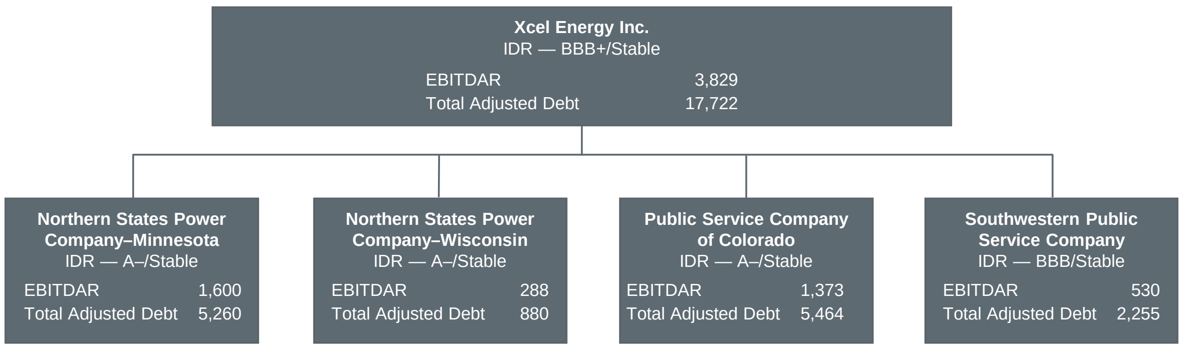
CREDIT-RELEVANT ESG SCALE

How relevant are E, S and G issues to the overall credit rating?

5	Highly relevant, a key rating driver that has a significant impact on the rating on an individual basis. Equivalent to "higher" relative importance within Navigator.
4	Relevant to rating, not a key rating driver but has an impact on the rating in combination with other factors. Equivalent to "moderate" relative importance within Navigator.
3	Minimally relevant to rating, either very low impact or actively managed in a way that results in no impact on the entity rating. Equivalent to "lower" relative importance within Navigator.
2	Irrelevant to the entity rating but relevant to the sector.
1	Irrelevant to the entity rating and irrelevant to the sector.

Simplified Group Structure Diagram

Organizational Structure — Xcel Energy Inc.
($ Mil., as of Dec. 31, 2018)



IDR – Long-Term Issuer Default Rating.
Source: Fitch Ratings, Fitch Solutions, Xcel Energy Inc.

Peer Financial Summary

Company	Issuer Default Rating	Financial Statement Date	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	BBB						
	BBB	2018	1,933	423	5.8	4.4	4.3
	BBB	2017	1,918	435	5.6	3.6	3.8
	BBB	2016	1,851	429	5.5	3.3	3.7
Northern States Power Company-Minnesota	A–						
	A–	2018	5,122	1,316	6.6	3.4	3.3
	A–	2017	5,102	1,400	6.7	3.2	3.0
	A–	2016	4,900	1,318	6.4	3.3	3.4
Oklahoma Gas & Electric Co.	A–						
	A–	2018	2,270	646	4.9	4.0	3.9
	A	2017	2,261	703	5.5	3.6	3.9
	A	2016	2,259	663	5.3	3.2	3.1
Public Service Company of Colorado	A–						
	A–	2018	4,086	1,035	5.6	4.3	4.0
	A–	2017	4,043	1,142	6.6	3.5	3.4
	A–	2016	4,048	1,092	6.5	3.5	3.3
Public Service Company of Oklahoma	BBB						
	BBB	2018	1,547	292	5.3	4.1	4.7
	BBB	2017	1,427	244	4.7	4.8	4.8
	BBB	2016	1,250	202	4.4	5.4	4.2
Southwestern Electric Power Co.	BBB						
	BBB	2018	1,822	413	4.1	5.3	5.4
	BBB	2017	1,780	447	4.4	4.7	4.8
	BBB–	2016	1,748	466	4.5	4.7	5.4

Source: Fitch Ratings, Fitch Solutions.

Reconciliation of Key Financial Metrics

(USD Millions, As reported)	31 Dec 2018
Income Statement Summary	
Operating EBITDA	522
+ 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)	**522**
+ Operating Lease Expense Treated as Capitalised (h)	**8**
= Operating EBITDAR after Associates and Minorities (j)	**530**
Debt & Cash Summary	
Total Debt with Equity Credit (l)	**2,192**
+ Lease-Equivalent Debt	63
+ Other Off-Balance-Sheet Debt	0
= Total Adjusted Debt with Equity Credit (a)	**2,255**
Readily Available Cash [Fitch-Defined]	44
+ Readily Available Marketable Securities [Fitch-Defined]	0
= Readily Available Cash & Equivalents (o)	**44**
Total Adjusted Net Debt (b)	**2,211**
Cash-Flow Summary	
Preferred Dividends (Paid) (f)	**0**
Interest Received	0
+ Interest (Paid) (d)	**(80)**
= Net Finance Charge (e)	**(80)**
Funds From Operations [FFO] (c)	**423**
+ Change in Working Capital [Fitch-Defined]	24
= Cash Flow from Operations [CFO] (n)	**446**
Capital Expenditures (m)	**(1,021)**
Multiple applied to Capitalised Leases	**8.0**
Gross Leverage	
Total Adjusted Debt / Op. EBITDAR* [x] (a/j)	**4.3**
FFO Adjusted Gross Leverage [x] (a/(c-e+h-f))	**4.4**
Total Adjusted Debt/(FFO - Net Finance Charge + Capitalised Leases - Pref. Div. Paid)	
Total Debt With Equity Credit / Op. EBITDA* [x] (l/k)	**4.2**
Net Leverage	
Total Adjusted Net Debt / Op. EBITDAR* [x] (b/j)	**4.2**
FFO Adjusted Net Leverage [x] (b/(c-e+h-f))	**4.3**
Total Adjusted Net Debt/(FFO - Net Finance Charge + Capitalised Leases - Pref. Div. Paid)	
Total Net Debt / (CFO - Capex) [x] ((l-o)/(n+m))	**-3.7**
Coverage	
Op. EBITDAR / (Interest Paid + Lease Expense)* [x] (j/-d+h)	**6.0**
Op. EBITDA / Interest Paid* [x] (k/(-d))	**6.5**
FFO Fixed Charge Cover [x] ((c+e+h-f)/(-d+h-f))	**5.8**
(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))	**6.3**
(FFO + Net Finance Charge - Pref. Div Paid) / (Gross Int. Paid - Pref. Div. Paid)	

*EBITDA/R after dividends to associates and minorities.
Source: Fitch Ratings, Fitch Solutions, Southwestern Public Service Company.

Fitch Adjustment Reconciliation

	Reported Values 31 Dec 18	Sum of Fitch Adjustments	Adjusted Values
Income Statement Summary			
Revenue	1,933	0	1,933
Operating EBITDAR	522	8	530
Operating EBITDAR after Associates and Minorities	522	8	530
Operating Lease Expense	0	8	8
Operating EBITDA	522	0	522
Operating EBITDA after Associates and Minorities	522	0	522
Operating EBIT	312	0	312
Debt & Cash Summary			
Total Debt With Equity Credit	2,168	24	2,192
Total Adjusted Debt With Equity Credit	2,168	87	2,255
Lease-Equivalent Debt	0	63	63
Other Off-Balance Sheet Debt	0	0	0
Readily Available Cash & Equivalents	44	0	44
Not Readily Available Cash & Equivalents	0	0	0
Cash-Flow Summary			
Preferred Dividends (Paid)	0	0	0
Interest Received	0	0	0
Interest (Paid)	(71)	(9)	(80)
Funds From Operations [FFO]	423	0	423
Change in Working Capital [Fitch-Defined]	24	0	24
Cash Flow from Operations [CFO]	446	0	446
Non-Operating/Non-Recurring Cash Flow	0	0	0
Capital (Expenditures)	(1,021)	0	(1,021)
Common Dividends (Paid)	(131)	0	(131)
Free Cash Flow [FCF]	(706)	0	(706)
Gross Leverage			
Total Adjusted Debt / Op. EBITDAR* [x]	4.2		4.3
FFO Adjusted Leverage [x]	4.4		4.4
Total Debt With Equity Credit / Op. EBITDA* [x]	4.2		4.2
Net Leverage			
Total Adjusted Net Debt / Op. EBITDAR* [x]	4.1		4.2
FFO Adjusted Net Leverage [x]	4.3		4.3
Total Net Debt / (CFO - Capex) [x]	-3.7		-3.7
Coverage			
Op. EBITDAR / (Interest Paid + Lease Expense)* [x]	7.3		6.0
Op. EBITDA / Interest Paid* [x]	7.3		6.5
FFO Fixed Charge Coverage [x]	6.9		5.8
FFO Interest Coverage [x]	6.9		6.3

*EBITDA/R after dividends to associates and minorities.
Source: Fitch Ratings, Fitch Solutions, Southwestern Public Service Company.

Related Research & Criteria

Northern States Power Company-Minnesota (Subsidiary of Xcel Energy Inc.) (July 2019)
Northern States Power Company-Wisconsin (Subsidiary of Xcel Energy Inc.) (July 2019)
Public Service Company of Colorado (Subsidiary of Xcel Energy Inc.) (July 2019)
Short-Term Ratings Criteria (May 2019)
Corporate Rating Criteria (February 2019)
Xcel Energy Inc. (October 2018)
Fitch Rates Northern States Power Company-Wisconsin's FMBs 'A+' (September 2018)
Parent and Subsidiary Rating Linkage (July 2018)
Corporates Notching and Recovery Ratings Criteria (March 2018)
Fitch Affirms Xcel Energy and Subs' Ratings; Outlook Stable (March 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

Public Utility Commission of Texas

General Information

Contact Information	1701 North Congress Avenue Austin, TX 78711-3326 (512) 936-7000
	http://www.puc.state.tx.us/
Number of Commissioners	3 of 3
Selection Method	Commissioners: Gubernatorial appointment, Senate confirmation Chairperson: Appointed by and serves at the pleasure of the Governor
Term of Office	Commissioners: 6 years Chairperson: Indefinite
Chairperson of Commission	DeAnn Walker
Deputy Chairperson of Commission	NA
Governor	Greg Abbott (R)
Service Regulated	Electric utilities, Telecommunications utilities, Water utilities
Commission Ranking	Average/3 (5/10/2017)
Commission Budget	$16.30 million
Commissioner Salaries	Commissioners: $189,500 Chairperson: $189,500
Size of Commission Staff	215
Company Name, Abbreviated	Public Utility Commission of Texas's Rate Case History
Research Notes	RRA Articles
RRA Contact	Lillian Federico

Commissioners

PERSON'S NAME	PARTY ABBREVIATION	DATE ROLE BEGAN	TERM ENDS
DeAnn Walker Chairman	R	09/2017	08/2021
Arthur D'Andrea	R	11/2017	08/2023
Shelly Botkin	R	06/2018	08/2019

RRA Ranking History

DATE OF RANKING CHANGE	COMMISSION RANKING
5/10/2017	Average / 3
5/11/2001	Below Average / 1
5/1/1999	Average / 3
4/1/1998	Below Average / 1

DATE OF RANKING CHANGE	COMMISSION RANKING
4/4/1997	Below Average / 2
7/16/1993	Below Average / 1
12/18/1992	Below Average / 2
3/1/1992	Below Average / 1
10/10/1990	Average / 3
3/29/1989	Below Average / 1
2/24/1988	Average / 3
4/18/1986	Average / 2
12/1/1985	Average / 1
2/15/1983	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

Elections

Gov. Gregg Abbott won re-election on Nov. 6, 2018, to a term extending to January 2023. He defeated Lupe Valdez, a Democrat and Dallas County Sheriff, and several third-party candidates. The Republicans retained majorities in both chambers of the state legislature.

Commissioner selection criteria

Minority party representation is not required. Senate confirmation requires a two-thirds vote.

An appointee to the PUC must be a qualified voter and a citizen of the U.S., be a "competent" and experienced administrator, be well informed and qualified in the field of public utilities and public utility regulation and have a minimum of five years of experience in the administration of business or government or as a practicing attorney or certified public accountant.

An individual would be excluded from consideration for nomination to the PUC if at any time during the two years preceding the nomination that individual has served as an officer, director, owner, employee, partner or legal representative of a public utility regulated by the commission or of an affiliate or direct competitor of a public utility regulated by the commission or if that individual has owned or controlled, directly or indirectly, more than a 10% interest in a public utility regulated by the commission or in an affiliate or direct competitor of a public utility regulated by the commission.

In addition, an individual is required to "register as a lobbyist under Chapter 305, Government Code," because the "person's activities for compensation on behalf of a profession related to the operation of the commission," the individual "may not serve as a commissioner " or if the individual is employed by a trade association.

A person is not eligible for appointment as commissioner or executive director of the commission if the person serves on the board of directors of a company that supplies fuel, utility-related services or utility-related products to regulated or unregulated electric or telecommunications utilities or if their spouse is employed by an entity regulated by the PUC, has a business relationship with the commission and/or has an interest in a mutual fund or retirement fund in which more than 10% of the fund's holdings at the time of appointment is in a single utility, utility competitor or utility supplier in this state unless the pre-existing relationship is severed.

Commission membership

Commissioners that are newly appointed or reappointed while the legislature is not in the midst of a regular session may serve pending Senate confirmation; however, those appointed while the legislature is in session may not begin serving until confirmation is granted. A commissioner that is appointed while a special session is underway may serve pending confirmation in the next regular session. If a commissioner is appointed or reappointed while the legislature is out of session and not confirmed before the end of the next legislative session, then the commissioner must leave office.

All three of the serving commissioners were initially appointed while the legislature was not in session: In September 2017, Gov. Abbott appointed DeAnn Walker to the PUC for a term extending through August 2021 and named her Chairman. On Nov. 14, 2017, Abbott appointed Arthur D'Andrea to a new six-year term extending to August 2023, and on June 11, 2018, Abbott named Shelly Botkin to fill the vacancy created by the departure of then-Commissioner Brandy Marty Marquez in April 2018.

On Feb. 21, 2019, the Senate Nominations committee endorsed the appointments, and the full Senate approved all three nominations on Feb. 27, 2019.

Services regulated

In addition to investor-owned vertically integrated electric utilities and telecommunications local exchange carriers, the PUC also regulates investor-owned electric transmission and distribution utilities and transmission rates for rural electric cooperatives and municipally owned utilities. In addition, the PUC oversees ERCOT, the registration of power generation companies, competitive retail electric providers and aggregators and, since 2014, water and wastewater utilities. Local gas distribution companies are currently regulated by the Railroad Commission of Texas.

In Texas, the cities grant the franchise to serve to the utilities and have "original jurisdiction" to set distribution rates within the confines of the city. The PUC has original jurisdiction over unincorporated areas outside of the city limits that are part of utility's service territory and appellate jurisdiction over the area within the city limits, meaning that the companies can appeal a rate order by a city or cities to the PUC. In practice, cities have generally ceded original jurisdiction to the PUC and then intervene in the case before the PUC.

Sunset review

The role/duties of the PUC are reviewed by the Sunset Advisory Commission periodically. Following such a review, legislation was enacted in 2013 extending the PUC through Sept. 1, 2023.

Commission budget

The budget for the 2018/2019 biennium, which runs from Sept. 1, 2017 through Aug. 31, 2019, is $32.6 million divided evenly between the two years, or $16.3 million per year.

Commission staff

A staff of 215 positions are authorized for the 2018/2019 biennium, which runs from Sept. 1, 2017 to Aug 31, 2019. There are currently roughly 185 staff members serving.

Commission contact — John Paul Urban, Executive Director—(512) 936 7040 (Section updated 4/23/19)

RRA Evaluation

Regulatory Research Associates, a group within S&P Global, views the regulatory climate in Texas as somewhat more restrictive than average from an investor viewpoint. The state is segmented in that the service territories within the Electric Reliability Council of Texas, or ERCOT, were restructured in 2002 to unbundle electric service and allow customers to select their generation supplier. Texas is unique among jurisdictions that restructured in that incumbent delivery utilities do not have the obligation to provide default service and so have no power market exposure whatsoever. The utilities that have not implemented retail access are subject to traditional regulation. Both restructured and traditional utilities have mechanisms in place that accord them expedited recognition of delivery infrastructure investment and allow them to pass through transmission costs, while vertically integrated utilities have fuel and purchased power cost adjustment provisions in place. However, the commission continues to rely on test years that are historical at the time a case is filed for both rate cases and capital investment recovery mechanisms. In addition, in rate cases conducted in the last couple of years, the PUC has adopted equity returns that were about the same for the delivery-only and vertically integrated companies. Consequently, the returns were about in line with prevailing industry averages for delivery-only companies but below the average for vertically integrated companies. For the utilities within ERCOT, the PUC has continued to utilize hypothetical capital structures that are more highly leveraged than the utilities' actual capital structures. All else being equal, this can render it challenging for the utilities to earn the authorized returns. Legislation is under consideration that would provide an expedited recovery mechanism for new generation investment by the non-ERCOT companies. With respect to mergers, the PUC has generally been even-handed in its approach; however, the commission faced some unique challenges in recent years in addressing proposed transactions that involved a utility whose parent company was in the midst of a bankruptcy reorganization. There has been quite a bit of turnover in recent years and all three of the commissioners are relatively new in their positions, adding a measure of uncertainty. RRA accords Texas an Average/3 ranking as it pertains to electric utilities under the PUC's purview. (Section updated 4/23/19)

Commission Staff

A staff of 215 positions are authorized for the 2018/2019 biennium, which runs from Sept. 1, 2017 to Aug 31, 2019. There are currently roughly 185 staff members serving.

The Commission Office of Policy & Docket Management is responsible for strategic issue analysis and planning and advises the commissioners in contested rate cases. The Divisions of Rate Regulation, Competitive Markets, Infrastructure & Reliability and Water Utility Regulation provide testimony and analysis in proceedings before the PUC. The Customer Protection Division addresses consumer complaints. The Legal Division represents the staff in regulatory proceedings, and the Oversight and Enforcement Division conducts enforcement activities. (Section updated 4/23/19)

Consumer Interest

The PUC staff represents the public interest in all proceedings. An independent agency, the Office of Public Utility Counsel, or OPUC, represents the interests of residential and small commercial customers. The OPUC has a staff of 18 and is headed by the Public Utility Counsel, who is appointed by the governor to a two-year term with the advice and consent of the Senate. The current Public Utility Counsel is Cassandra Quinn, who is serving on an interim basis. The OPUC's annual budget approximates $2 million. (Section updated 4/23/19)

Rate Case Timing/Interim Procedures

Base rate case filings

Legislation enacted in 2015 requires utilities that operate outside of the Electric Reliability Council of Texas, or ERCOT, to file a base rate case every fourth year, with a possible extension to that deadline if the commission determines that a rate case would not result in materially different rates. Nothing precludes the companies from filing sooner, and the non-ERCOT companies have generally filed well within the four-year time frame.

Legislation enacted in 2017, required the PUC to develop a schedule that requires each electric utility within ERCOT to make periodic filings with the commission to modify or review base rates. In April 2018, the PUC adopted filing requirements for utilities within ERCOT, as required by 2017 legislation. The new rules require each ERCOT utility to file for a comprehensive rate review within 48 months of the order setting rates in its most recent comprehensive rate proceeding or other proceeding in which the commission approved a settlement agreement reflecting a rate modification that allowed the electric utility to avoid the filing of such a rate case. For a transmission and distribution utility, the filing must include information necessary for the review of both transmission and distribution rates. The filing deadline may be extended: if the company’s most recent annual earnings monitoring report demonstrates that the utility is earning, on a weather-normalized basis, and using a 10-year period an ROE that is less than the last authorized ROE for that company plus 50 basis points; for good cause shown; or due to commission timing constraints.

Earnings monitoring reviews

In addition, the PUC monitors the utilities' earnings on an annual basis. Each May, the utilities file financial data for the previous calendar year. The PUC staff then conducts a review of these filings and makes recommendations to the commission concerning whether there is a potential for over-earnings. If so, the PUC may require the utility to tender a "complete rate filing package" in order to determine whether a rate change is necessary. Once such a filing is submitted, the 185-day clock applies. The PUC has occasionally exercised this option.

In addition, the cities have the authority to call the utilities in for a rate review; however, this happens infrequently.

Rate case process

When filing for a base rate increase with the PUC, utilities are required to submit a complete filing 35 days prior to the proposed effective date of the new rates. The PUC may suspend a requested rate increase for 150 days from the proposed effective date, bringing the total elapsed time from the date of filing to 185 days. If no PUC decision is forthcoming within 185 days, and the PUC has extended the suspension period beyond the initial statutory time frame, the utility may place the proposed rates into effect, under bond and subject to refund.

The PUC may, at the request of a utility, establish "temporary" rates to be in effect during the suspension period; this has rarely, if ever, occurred.

In addition, the law provides that the rates charged by the utility on the 185th day after the date the utility files a rate filing package automatically become temporary rates if the PUC has not issued a decision or if the suspension period has been suspended beyond the initial 185 days. Legislation enacted in 2015 that is applicable only to non-ERCOT utilities modified the statute to allow the final rates approved in a rate case to be retroactive to an effective date 155 days after the filing of the rate application if the PUC has not rendered a decision by that time. This is known as the "relate back" date.

If a rate increase is approved, the company may implement a surcharge to collect the unrecovered revenue from the date the rates became temporary until the date billing under the new rates begins. If a rate decrease is ordered, the company would be required to refund the related over-collections with interest.

In a contested rate case, a motion for rehearing may be filed within 25 days after the PUC's final decision, unless extended by the PUC. Replies to the motion for rehearing must be tendered within 40 days after the issuance of the final order in the case the motion refers to. The PUC must respond to a motion for rehearing within 55 days after the issuance of the final order in the case. (Section updated 4/23/19)

Rate Base and Test Period

The PUC utilizes a terminal, i.e., year-end rate base value for a 12-month historical test period, with adjustments permitted for post-test-year plant additions and retirements, under certain circumstances.

With the exception of certain environmental compliance costs, the PUC generally has not permitted the utilities to include construction work in progress, or CWIP, in rate base for a cash return, and has only allowed it following a finding that such treatment was necessary to maintain the utility's financial integrity. However, the companies are permitted to adjust rates through surcharge mechanisms to reflect certain types of new transmission and distribution investment that goes into commercial operation between rate cases, thus reducing the regulatory lag (see the Adjustment clauses section).

Legislation enacted in 2015 changed the rate case filing provisions for vertically integrated utilities outside of the Electric Reliability Council of Texas, or ERCOT, allowing the companies to propose adjustments to test-year data that include actual information for an update period and permitting post-test-year adjustments for a new natural-gas-fired plant.

Pending legislation would allow the non-ERCOT companies to reflect new generation investment in rates through a rider mechanism outside of base rates (see the Legislation section). (Section updated 4/23/19)

Return on Equity

For those utilities whose territories have been restructured in accordance with state law, i.e., American Electric Power Co. subsidiaries AEP Texas Central Co., or TCC, and AEP Texas North Co., or TNC, Sempra Energy Inc. subsidiary Oncor Electric Delivery Co., PNM Resources Inc. subsidiary Texas-New Mexico Power Co., or TNMP, CenterPoint Energy Inc. subsidiary CenterPoint Energy Houston Electric Co., or CEHE, and Sharyland Utilities LP, which is owned by an investor group led by Hunt Consolidated, the PUC no longer regulates prices charged for generation service (see the Electric regulatory reform/industry restructuring section). The PUC continues to regulate transmission and distribution, or T&D, rates for all of these entities located within the Electric Reliability Council of Texas, or ERCOT. TCC and TNC were merged in 2016 and are now both part of AEP Texas Inc.

The most recent decision specifying an ROE for a restructured T&D-only company was issued on Dec. 20, 2018, when the PUC adopted a rate case settlement for TNMP that specified a 9.65% ROE.

Prior to that, in September 2017, the PUC approved an asset swap-related settlement (see the Merger activity section) for Oncor that specified a 9.8% ROE.

In 2011, the PUC approved a 10% ROE for CEHE, and in 2007, the PUC approved a 9.96% ROE for TCC that also applied to utility affiliate TNC.

Implementation of retail competition has been delayed for investor owned utilities located outside of ERCOT, i.e., American Electric Power subsidiary Southwestern Electric Power Company, or SWEPCO, Entergy Corp. subsidiary Entergy Texas Inc., or ETI, El Paso Electric Company, or EPE, and Xcel Energy Inc. subsidiary Southwestern Public Service Co., or SWPS; these entities remain vertically integrated and are subject to traditional regulation.

In the most recent cases that specified an ROE for a vertically integrated utility in Texas, both decided in December 2017, the PUC adopted a settlement authorizing a 9.65% ROE for EPE and in a fully litigated case authorized SWEPCO a 9.6% ROE — final orders were issued later.

In a Dec. 20, 2018 decision for Entergy Texas Inc., the PUC adopted a settlement that was silent with respect to rate case parameters underlying the stipulated rate change but specified that the company is to use a 9.65% ROE to calculate the revenue requirement under its distribution cost recovery factor and transmission cost recovery factor (see the Adjustment clauses section).

In a 2016 order on rehearing of a 2015 decision, the PUC authorized SWPS a then-below-industry-average 9.7% ROE. More recently, a Dec. 7, 2018 rate case decision for SWPS adopted a settlement that was silent with respect to the parameters underlying the stipulated rate increase, but a 9.5% ROE is to be used to calculate allowance for funds used during construction on new investment, down from 9.6% approved in a January 2017 decision.

There are also several transmission-only utilities in Texas that were established to construct and operate transmission lines for newly constructed facilities in the state's designated competitive renewable energy zones (see the Integrated resource planning section). In 2015, the PUC approved a 9.6% ROE for Cross Texas Transmission LLC, whose ultimate parent is LS Power Group. In 2014, the PUC approved a 9.6% ROE for Lone Star Transmission LLC. Lone Star is a subsidiary of NextEra Energy Inc.

In 2013, the PUC set the initial revenue requirement for Wind Energy Transmission Texas LLC, or WETT, utilizing a 9.6% ROE. WETT is owned 50% by Isolux Corsan Concesiones, S.A. and 50% by Brookfield Asset Management Inc.

The PUC approved a 9.96% ROE in a 2007 rate decision that established initial tariffs for then-newly formed Electric Transmission Texas LLC, which is jointly owned by American Electric Power and Berkshire Hathaway Energy subsidiary MidAmerican Transmission LLC. In February 2017, in order to avoid being required to file a rate case, the company entered into a settlement calling for a rate reduction that reflected a 9.6% ROE.

Following a review of the companies' 2017 earnings reports, on Sept. 20, 2018, the staff found that the utilities had earned ROEs ranging from 5.58% for Entergy Texas to 12.43% for WETT. On Dec. 8, 2018, the PUC voted to direct WETT to file a rate case by Feb. 13, 2019. However, on Dec. 20, 2018, the PUC voted to adopt a settlement resolving the issue; a final order was issued on April 4, 2019. The settlement called for the company to reduce its wholesale transmission rates by $16 million effective Jan. 1, 2019. In addition, WETT agreed to forego adjustments under its interim transmission cost-of-service procedure to reflect $32 million of investment that has not yet been reflected in rates. As a result, the show cause order was rescinded. (Section updated 4/23/19)

Accounting

Nuclear decommissioning

Historically, utilities have been permitted to recover the Texas jurisdictional share of estimated nuclear decommissioning costs over the lives of the related facilities, with the collected amounts deposited in external trusts.

For companies that remain vertically integrated, including El Paso Electric Co., or EPE, and Entergy Texas Inc., this practice continues. In a December 2017 rate case decision for EPE, the PUC approved a settlement specifying a Texas-jurisdictional amount of $2.1 million for nuclear decommissioning funding.

For companies that implemented retail competition, decommissioning costs for previous Texas jurisdictional assets are recovered through non-bypassable charges on electric delivery customers, with amounts collected remitted to the external trusts held by competitive generation owners. Companies affected by this practice include CenterPoint Energy Houston Electric Co., Oncor Electric Delivery Co. and AEP Texas Inc. The actual responsibility for decommissioning the units now resides with the competitive generation companies.

Deferrals and trackers

The base rates of many of the transmission and distribution utilities include modest amounts to fund reserves for storm-related costs. To the extent such costs exceed amounts accrued in the reserves, the utilities have been permitted to defer these costs, with recovery of the deferrals addressed in a subsequent base rate case. Typically, recovery of the deferrals has been granted over a five-to-seven-year period, with no return on the unamortized balance. Capital costs related to construction of replacement facilities have been included in rate base in subsequent rate proceedings. State law permits extraordinary storm-related costs to be securitized (see the Securitization section).

Southwestern Public Service Co., or SWPS, utilizes a pension and other post-employment-benefit tracker mechanisms such that to the extent the related costs vary from the level reflected in rates, SWPS may defer the difference in an accrual account; treatment of any balance in the account is addressed in subsequent rate cases.

As part of an asset swap and related rate case settlement approved by the PUC in October 2017, Oncor was required to achieve a capital structure with a 42.5% equity ratio by Nov. 27, 2017, or the company would have to accrue a regulatory liability reflecting the resulting revenue requirement difference. Oncor did not achieve the target equity ratio until May 4, 2018. On July 9, 2018, Oncor filed to refund roughly $6 million of related over-collections to ratepayers. The PUC approved the filing at its Sept. 14, 2018 open meeting.

On Aug. 7, 2018, AEP Texas, Inc. filed (Docket No. 48577) for a PUC determination that $415 million of restoration costs associated with Hurricane Harvey and certain other storms accrued through April 30, 2018, are eligible for recovery. In addition, the company seeks authorization to accrue carrying charges on the costs at the company's weighted average cost of capital. On Nov. 28, 2018, the parties filed a settlement quantifying reasonable restoration costs, net of insurance proceeds, at $369 million. Certain of these costs would be deferred with carrying costs and would be eligible for securitization. The PUC approved the settlement on Feb. 17, 2019. On March 8, 2019, the company filed (Docket No. 49308) for approval to securitize $225 million of the costs, plus $4.6 million of up front issuance costs.

As part of a rate case settlement adopted by the PUC for Texas-New Mexico Power Co., or TNMP, on Dec. 20, 2018, TNMP is to recover $6.6 million of deferred Hurricane Harvey restoration costs plus carrying charges through a surcharge, subject to the aforementioned offset, over five years. In addition, TNMP is to increase the annual storm cost accrual to $1,006,500 for five years. If another rate case is not adjudicated by the end of the five years, the accrual is to be automatically reduced to $349,700.

Consolidated tax adjustments

Historically, the PUC had imposed consolidated tax adjustments for utilities that are part of holding companies that file consolidated taxes. Such adjustments were designed to flow to ratepayers tax benefits associated with losses on unregulated affiliate businesses. Legislation enacted in 2013 prohibits the PUC from imposing such adjustments prospectively.

However, in the context of the PUC's 2016 conditional approval of the acquisition of Oncor by a consortium of investors led by Hunt Consolidated, the commission required that any tax benefit associated with the planned reorganization of Oncor as a real estate investment trust, or REIT, be accrued as a regulatory liability. The rate treatment to be accorded the liability was to be addressed in Oncor's next rate case. The transaction was subsequently terminated (see the Merger activity section), but the PUC had opened a generic project to address the tax issues. That project has not been active since the merger was terminated.

In a recent rate case for Sharyland Utilities, which is organized as a REIT, the tax issue also became controversial. However, the proceeding was resolved in September 2017, when the PUC approved a black box rate settlement that had been filed in conjunction with a proposed asset swap between Sharyland and Oncor (see the Merger activity section).

Federal tax reform

At its Jan. 11, 2018 open meeting, the PUC directed the staff to open a docket wherein the state's investor-owned electric utilities are to provide data on the revenue impacts of the 2017 federal tax changes, signed into law by President Donald Trump on Dec. 22, 2017, lowering the corporate federal income tax rate to 21% from 35%.

On Feb. 15, 2018, the PUC issued an order directing that, until a rate change reflecting the reduced federal income tax rate can be implemented, effective Jan. 25, 2018, the electric utilities are to begin recording a regulatory liability that reflects:

1. The difference between the revenues collected under existing rates and the revenues that would have been collected had the existing rates been set using the recently approved federal income tax rates.

2. The balance of accumulated deferred federal income taxes that now exists because of the decrease in the federal income tax rate from 35% to 21%.

The order directed the PUC staff to "investigate each investor-owned utility in Texas, with input from interested stakeholders, on a case-by-case basis ... to determine the appropriate mechanism to adjust its rates to reflect the changes under the newly enacted federal tax law." The companies filed testimony under this docket, most of which was confidential. However, steps to address tax reform have been undertaken in various proceedings.

In pre-emptive action, in the context of Dec. 14, 2017 rate case decisions for EPE and Southwestern Electric Power Company, or SWEPCO, the PUC adopted provisions to address prospective changes in federal tax rates. Specifically, the company was directed to record as a regulatory liability, any difference in tax expense associated with a change in federal tax law. The regulatory treatment of any excess deferred taxes resulting from a reduction in the federal income tax rate will be addressed in the next base rate case.

In addition, EPE was directed to file a "refund tariff" that is to provide for the refund of the accrued liability over a 12-month period. In each subsequent year, El Paso is to be required to update the refund factor to reflect any over- or under-recovery of federal income tax expense and to reflect any subsequent changes in federal income tax rates or calculations that would affect the settlement income tax calculation. The refund factors in each subsequent year are to be filed within 90 days of the end of El Paso's fiscal year. The refund factor will be discontinued upon the effective date of rates in El Paso's next base rate case, with a final reconciliation to occur in the base rate case.

Similar provisions had been included in a settlement adopted by the PUC in a September 2017 rate case decision for Oncor Electric Delivery.

In accordance with the rate case order, on March 1, 2018, EPE tendered its tax reform filing (Docket No. 48124). El Paso proposed to implement a federal income tax refund tariff and base rate credit designed to return approximately $27 million to Texas-jurisdictional customers over a 12-month period beginning April 1, 2018. The $27 million figure included the $22.7 million annual effect of the reduction in the federal income tax rates on the tax expense reflected in El Paso's last rate case and $4.3 million related to over-collections from Jan. 1, 2018 through March 31, 2018; the latter is to be implemented as a credit that will be amortized over a 12-month period. The proposal was approved by the PUC on Dec. 10, 2018.

On April 5, 2018, SWEPCO tendered a filing (Docket No. 48233) proposing to reduce rates by $18.1 million versus the level approved in the above-noted rate case to reflect the prospective impact of the lower tax rate. In addition SWEPCO proposed, upon a determination of the effective date of the new rates, to calculate the reduction in its rates that would have occurred had the lower income tax rate been in effect from Jan. 1, 2018 through the effective date of the new rates and to use that amount to offset SWEPCO's ongoing recoveries under the Temporary Rate Reconciliation Rider approved in the rate case for recovery of under-collections from the "relate back" date to the date new rates were implemented under the final order. A settlement in principle was reached on Aug. 17, 2018, and on Sept. 11, 2018, the ALJ approved the parties proposal to implement the proposed rate reduction on an interim basis. The proposal was approved by the PUC on Dec. 20, 2018.

In a wholesale interim transmission cost of service, or TCOS, filing tendered in January 2018 and approved March 29, 2018, in Docket No. 47988, Oncor lowered the incremental revenue requirement by about $52 million to reflect the impact of the federal tax changes. In a distribution cost recovery factor, or DCRF, application filed on April 5, 2018, Oncor indicated that it was not modifying the filing to reflect the tax reform impacts, but would instead file a stand-alone tax proceeding by May 1, 2018.

On May 1, 2018, Oncor tendered the promised filing (Docket No. 48325) to address the tax reform impacts on transmission and distribution base rates. Oncor proposes a net $181.5 million revenue requirement reduction versus that approved in its prior base rate case, Docket No. 46957. The $181. 5 million decrease comprises the following: a $67 million reduction in the TCOS revenue requirement, which includes the $52 million approved in Docket No. 47988; and, a $114 million reduction in retail transmission and distribution rates, which includes a $24 million reduction that will flow through the TCRF. About $149 million of the reduction flows from the prospective impact of the lower tax rate and $32 million relates to the return of excess accumulated deferred federal income taxes, or EADFIT. In addition, in November 2018, Oncor would make one-time refunds aggregating to $12.2 million to return to ratepayers over-collections related to the Jan. 1, 2018-through-March 30, 2018 period. The company would refund any incremental over-collections dating back to Jan. 1, 2018, along with over-collections from April 1, 2018 through the date new rates are implemented, via separate riders that would be known as Rider WTRF, for wholesale transmission service, and Rider TRF, for retail transmission and distribution operations.

On Sept. 7, 2018, the parties reached a settlement calling for a $218.8 million revenue requirement, reflecting the ongoing impact of the lower tax rate, the amortization of protected EADFIT balances using the average rate assumption method, or ARAM, with the related amortization expense for the first nine months of 2018 to be deferred and returned to ratepayers over a five-year period, and the amortization of unprotected EADIT balances over a 10-year period. A carrying charge of 3.25% would be applied to the amount of tax expense collected by Oncor, in excess of the amount that would have been collected based upon the impacts of the tax overhaul, for the period Jan. 1, 2018, through the effective date of new rates. The aggregate liability would be returned to ratepayers through a one-time credit applied during the billing month beginning on Nov. 26, 2018. The settlement rates were implemented on an interim basis. The PUC approved the agreement at its April 4, 2019 open meeting.

CenterPoint Energy Houston Electric Co., or CEHE, indicated that it intended to address the tax-reform-related impacts on a near-term basis through its TCOS and DCRF, mechanisms. CEHE filed a TCOS update (Docket No. 48065) on Feb. 16, 2018, that addressed only tax reform impacts. The company proposed to reduce the revenue requirement being collected under the TCOS factor by $41.6 million. The PUC approved the TCOS filing on April 27, 2018.

CEHE filed its DCRF update, Docket No. 48226, on April 4, 2018, requesting a $7 million DCRF revenue requirement reduction, versus the $32 million increase the company would have sought absent the federal tax change. On Aug. 30, 2018, the PUC approved a settlement calling for a $40.4 million reduction in the DCRF, including the refund over one year, of 2018 over collections. Effective Sept. 1, 2019, the DCRF revenue requirement would rise by $22.2 million. The settlement provides for the amortization of unprotected EADIT balances over a five-year period.

In a wholesale transmission update (Docket No. 48389) filed on May 25, 2018, CEHE proposes to refund $6.6 million of over-collections from Jan. 25, 2018 through April 26, 2018. The PUC approved the filing on July 11, 2018. In a base rate case filed on April 5, 2019, CEHE proposes to return the remaining balance of federal tax reform-related unprotected EADFIT liabilities to ratepayers over a three-year period through a separate rider, reflecting an annual credit of $32.4 million.

On March 1, 2018, AEP Texas filed, in Docket No. 48122, an updated TCOS to reflect the impact of the federal tax reform. The company proposed to reduce TCOS rates by $23.8 million to reflect the prospective reduction in the federal corporate income tax rate, but did not address refunds for over-collections or the return of excess accumulated deferred taxes. On May 1, 2018, the parties filed a settlement calling for approval of the rate reduction and for the company to defer for future regulatory treatment any amortization of the protected and unprotected EADFIT that it makes for accounting purposes and reflect such deferred liability amounts in the determination of the company's rates in its next base rate application. The PUC adopted the settlement on June 29, 2018.

On April 3, 2018, AEP Texas filed an update (Docket No. 48222) to its DCRF, in which the company proposed an approximate $3.1 million net increase after reflecting a $20.7 million revenue requirement reduction associated with the lower federal corporate income tax rate. On Aug. 30, 2018, the PUC adopted a settlement specifying a $27 million DCRF rider revenue requirement reduction. The proposed revenue requirement had reflected the prospective impact of tax reform only, while the settlement/order reflected the amortization of protected EADIT liabilities using the ARAM method amortization of unprotected EADIT liabilities over a five year period. AEP Texas is to file a base rate case by May 1, 2019.

Tax reform issues for Sharyland Utilities were addressed in the context of an interim TCOS proceeding, Docket No. 47649, in which the PUC was addressing updates to rates to reflect an asset swap with Oncor (see the Merger activity section). The revenue requirement approved by the PUC on March 14, 2018, incorporated a $20.2 million decrease in tax expense related to federal tax reform. EADFIT issues are to be addressed in Sharyland's next base rate case; related revenue requirement variations are being deferred in the meantime. Sharyland is to file its next base rate case by July 1, 2020.

On Feb. 23, 2018, Lone Star Transmission LLC filed an interim TCOS update (Docket No. 48101) solely addressing the reduction in federal tax rates. The company proposed a $7.3 million revenue requirement decrease. The PUC approved the updated TCOS revenue requirement on April 26, 2018, noting that the federal tax reform would not result in any significant change to Lone Star's current amortization of its excess deferred tax liability. Lone Star's transmission assets were placed into service in 2012, and Lone Star does not expect the reversal of the timing differences related to accelerated tax depreciation of its assets to occur for several years. The reduction is being implemented through a rider. Lone Star is to file its next rate case by Sept. 1, 2020.

On March 8, 2018, Wind Energy Transmission Texas LLC, or WETT, filed (Docket No. 48127) for approval to implement an interim TCOS rider, effective April 1, 2018, reflecting a $9.7 million revenue requirement reduction associated with federal tax reform. The company also proposed to refund $1.8 million of over-collections for the period Jan. 1, 2018 to March 31, 2018. The PUC approved the proposal on April 26, 2018. WETT is to file its next base rate case by Oct. 1, 2019.

On March 16, 2018, Cross Texas Transmission LLC filed (Docket No. 48179) for approval to implement an interim TCOS rider, effective April 1, 2018, reflecting a $4.1 million revenue requirement reduction associated with federal tax reform. Cross Texas also proposed to refund $0.7 million of over-collections for the Jan. 1, 2018 to March 31, 2018 period. Cross Texas later updated the proposal to reflect a $5.2 million revenue requirement reduction and $1.3 million refund, with new rates effective May 1, 2018. The PUC approved the proposal on May 1, 2018. Cross Texas is to file its next base rate case by Feb. 3, 2020.

In an interim TCOS update filed on May 2, 2018 (Docket No. 48340), Electric Transmission Texas LLC indicated that the proposed revenue requirement includes a $27 million reduction related to federal tax reform. The PUC approved the filing on June 20, 2018. The company is to file its next base rate case by Feb. 1, 2021.

For Southwestern Public Service Co., the impacts of tax reform were addressed in a base rate case decided on Dec. 6, 2018. The PUC adopted a settlement leaving rates unchanged, and so there were no "over collections." The stipulated revenue requirement reflects the lower federal corporate tax rate as well as the amortization of protected and unprotected EADFIT balances using the ARAM, essentially over the remaining life of the assets that gave rise to them. In future cases, protected EADFIT amounts are to be amortized in accordance with ARAM; unprotected, non-plant, EADFIT balances are to be amortized over five years; and net operating loss-related balances are to be amortized over a 44-year period, in accordance with the ARAM method. In addition, a 58% equity ratio was adopted in order to reflect planned increases in SWPS' equity layer to counteract the cash flow/credit impacts of federal tax reform.

A rate case settlement adopted for Entergy Texas Inc. approved by the PUC on Dec. 20, 2018, calls for an unprotected excess accumulated deferred tax liability of $185.2 million to be returned to customers, with the liability to be amortized over four years for residential and small commercial customers and over 12 months for large-volume customers; a 7.73% carrying charge is to accrue on the unamortized balance. Consistent with the company filing, the settlement and order call for the amortization of the protected portion of the tax reform-related EADFIT liability using the average rate assumption method. In addition, Entergy Texas was required to provide $25 million in rate credits to return tax reform-related over-collections from January through December 2018 to large-volume customers over 10 months and to residential and small commercial customers over four years.

In a rate case settlement adopted by the PUC for Texas-New Mexico Power Co. on Dec. 20, 2018, the approved revenue requirement reflects the ongoing reduction in current tax expense occasioned by the reduction in the federal corporate income tax rate to 21% from 35%. The related protected EADFIT liabilities are to be returned to ratepayers according to the average rate assumption method, and unprotected amounts are to be amortized over five years. Accrued over-collections from January through December 2018, which aggregated to $3.8 million as of Aug. 31, 2018, are to be used to offset deferred storm restoration costs associated with Hurricane Harvey. (Section updated 4/23/19)

Alternative Regulation

Electric utilities are permitted to request recovery of costs associated with legislatively mandated energy efficiency programs through a streamlined adjustment mechanism. AEP Texas, CenterPoint Energy Houston Electric, El Paso Electric, Entergy Texas, Oncor Electric Delivery, Southwestern Electric Power Company, Southwestern Public Service, or SWPS, and Texas-New Mexico Power each have such mechanisms in place.

The utilities are also permitted streamlined rate treatment for transmission system investment, distribution system investment and smart grid deployment (see the Adjustment clauses section).

SWPS retains the first $0.4 million of proprietary book/commodity trading margin and 45% of any incremental margin; the remainder flows to ratepayers. (Section updated 4/23/19)

Court Actions

PUC decisions may be appealed to the District Court of Travis County. Further appeals may be made to the Third Court of Appeals in Austin and then to the Texas Supreme Court.

Entergy Texas appealed a 2012 rate order in which the PUC denied the company recovery of about $40 million in capacity payments and other transmission-related costs, finding that the company had failed to provide adequate support for the request. The PUC decision has been upheld by the District Court and the Appeals Court, and in 2016 Entergy appealed the lower court rulings to the Texas Supreme Court; the appeal is pending.

On July 13, 2017, NextEra Energy filed an appeal with the Travis County district court of the PUC's June 2017 orders rejecting NextEra's proposed acquisition of Energy Future Holdings, parent of Oncor Electric Delivery. The appeal is largely moot as Oncor has since been acquired by Sempra Energy (see the Merger activity section). (Section updated 4/23/19)

Legislation

The bicameral Texas Legislature meets in odd-numbered years, beginning on the second Tuesday in January, for a 140-day session. However, the governor may convene a "special session" at his/her discretion.

The 2019 session convened on Jan. 8, and is to adjourn on May 27. Following the Nov. 6, 2018 elections, there are now 83 Republicans and 67 Democrats in the House and 19 Republicans and 12 Democrats in the Senate.

House Bill 223, filed on Nov. 12, 2018, for the 2019 session calls for a "greenhouse gas emissions charge" to be imposed on generation facilities in the amount of $5 per ton of carbon dioxide equivalent emitted from the facility each year. Half the funds collected each year would be allocated to fund low-income-customer assistance programs.

House Bill 400/Senate Bill 76 would establish a grid security council for the Electric Reliability Council of Texas, or ERCOT, power region for the purpose of monitoring economic, environmental, regulatory and technological developments that may affect the security of the electric grid. Senate Bill 475 would require the Texas Electric Grid Security Council to develop recommendations about grid security standards, preparation for events that threaten grid security and amendments to the state emergency plan "to ensure coordinated and adaptable response and recovery efforts after events that threaten grid security." The council would be composed of a member of the Texas PUC, the CEO of the Electric Reliability Council of Texas and a governor's appointee. The bill passed the Senate on April 3, 2019.

Senate Bill 15 would extend the timeline to 12 months from six months for the PUC to rule on wind energy permits.

House Bill 986 would allow utilities outside of ERCOT to file for PUC approval of advanced metering deployment plans and recovery of the associated costs. The PUC has approved deployment plans for the utilities within ERCOT and for Entergy Texas, under previous statutes. The bill was reported favorably out of the House State Affairs Committee on March 20, 2019.

Companion measures, Senate Bill 661 and House Bill 1397, introduced on Feb. 6, 2019, seek to address regulatory lag for electric utilities with service territories outside of ERCOT and encourage these companies to invest in new regulated generation investment within the state. If the bills are enacted in their current form, the PUC would be required to establish rules by Sept. 1, 2020 under which utilities outside of ERCOT would be able to seek recovery of new generation facilities via a limited-issue rider.

Senate Bill 941, introduced on March 7, 2019, would allow transmission and distribution utilities to enter into agreements with generators to provide electricity from energy storage facilities, with prior approval from the PUC. Under the bill, such agreements would be "limited to situations where construction of traditional distribution facilities is not cost-effective when compared to the use of an energy storage facility."

House Bill 3995/Senate Bill 1938 would remove language from the existing utility code that permits an entity other than an existing utility to construct, own and/or operate a transmission line in Texas. The bill states "A certificate for a new transmission facility that directly interconnects with an existing electric utility facility may only be granted to the owner of that existing facility. If a new transmission facility will directly interconnect with facilities owned by different electric utilities, one or both of those utilities shall be certificated to construct the new facility." (Section updated 4/23/19)

Corporate Governance

Affiliate relationships

By statute, the PUC has broad authority over affiliate relationships. The PUC's affiliate relationships rules require a utility to be legally separated from any competitive affiliate and maintain separate books and records. Any transactions between regulated and non-regulated entities must be conducted at arm's length. The utility may not allow an affiliate to obtain credit under any arrangement that would include a specific pledge of any assets in the rate base of the utility or a pledge of cash "reasonably necessary for utility operations."

Mergers/reorganizations

Legislation enacted in 2007 specifically granted the PUC authority to approve or reject utility mergers or reorganizations. Previously, state law only required a utility to notify the PUC of any potential change of ownership; however, merging entities generally filed for PUC affirmation that the proposed transaction was in the public interest. In many such instances the PUC imposed ring-fencing-like conditions (see the Merger activity section). In addition, the PUC has authority over bonds issued by regulated entities for securitization purposes.

In 2007, Entergy Gulf States, or EGS, completed a joint separation plan, dividing its operations into two distinct entities: Entergy Gulf States Louisiana, or EGS-LA, which is regulated by the Louisiana Public Service Commission; and, Entergy Texas, or ETI, which is regulated by the PUC.

Under the plan, EGS' transmission and distribution assets were separated based on their physical location. With regard to generation assets: the 70% share of the River Bend facility that is subject to state regulation was transferred to EGS, and ETI entered into a purchased power agreement, or PPA, for a share of the capacity equal to its responsibility ratio under the Entergy System Agreement; the remaining 30% of River Bend, which is unregulated, was also transferred to EGS; ownership of EGS' 42% interest in Big Cajun II unit 3 and 70% interest in Nelson 6 were split between EGS and ETI at varying levels; Louisiana 2, Nelson 3 and 4, and Willow Glen were transferred to EGS, and ETI entered into a PPA for a portion of the plants' capacity; the Sabine and Lewis Creek facilities were transferred to ETI, and EGS entered into a PPA for portion of the facilities' capacity; EGS' Perryville PPA was transferred to EGS, and ETI entered into a PPA for a portion of Perryville's capacity; and EGS and ETI retained their respective shares of the Toledo Bend PPA.

Foreign ownership

PUC rules state that utility holding companies may only invest in foreign utility companies, or FUCOs, if: any debt incurred as a result of the acquisition is without recourse to the Texas utility; neither the holding company nor any affiliate enters into any agreements under which the Texas utility is obligated to commit funds in order to maintain the financial viability of the FUCO; the Texas utility provides no direct or indirect guarantee or other form of credit support for funds borrowed by the holding company of the affiliate in connection with the acquisition of the FUCO; and the Texas utility is not liable for the debts and/or liabilities of the FUCO. (Section updated 4/23/19)

Merger Activity

State statutes

Historically, state law only required a utility to notify the PUC of any potential change of ownership. In practice, the utilities generally filed for PUC approval of mergers and reorganizations, and in certain instances, this resulted in the parties agreeing to certain "ring-fencing" and ratemaking provisions in order to gain PUC support for the transactions. However, legislation was enacted in 2007, requiring preapproval by the PUC before the completion of any merger involving an electric transmission and distribution utility, or TDU.

Current statutes address ownership of all or part of a utility business in different areas. Section 14 of the utility code states that the "commission may require disclosure of the identity and respective interests of each owner of at least [1%] of the voting securities of a public utility or its affiliate."

In addition, Section 14 of the utility code, states that unless a public utility reports the transaction to the commission within a reasonable time, the public utility may not: sell, acquire, or lease a plant as an operating unit or system in this state for a total consideration of more than $10 million; or, merge or consolidate with another public utility operating in this state. With respect to these transactions, the utility must report to the commission "within a reasonable time each transaction" that involves the sale of at least 50% of the stock of the utility. Following the filing of a report, the commission must investigate the transaction, with or without a public hearing, to determine whether the action is consistent with the public interest. In reaching its determination, the commission is to consider the reasonable value of the property, facilities or securities to be acquired, disposed of, merged, transferred, or consolidated and determine whether the public utility will receive consideration equal to the reasonable value of the assets when it sells, leases, or transfers assets. The PUC must also consider whether the transaction will: (1) adversely affect the health or safety of customers or employees; (2) result in the transfer of jobs of citizens of this state to workers domiciled outside this state; or (3) result in the decline of service. If the commission finds that a transaction is not in the public interest, the commission may take the effect of the transaction into consideration in ratemaking proceedings and disallow this effect if the transaction will unreasonably impact rates or service.

Section 39 requires any "electric utility or transmission and distribution utility" operating in the state to report and obtain approval of the commission before closing of any transaction in which: (1) the electric utility or transmission and distribution utility will be merged or consolidated with another electric utility or transmission and distribution utility; (2) at least 50% of the stock of the electric utility or transmission and distribution utility will be transferred or sold; or (3) a controlling interest or operational control of the electric utility or transmission and distribution utility will be transferred.

In order to approve a transaction under Section 39, the PUC must find that the transaction is in the public interest, after considering whether the transaction will adversely affect the reliability or cost of service of the electric utility or transmission and distribution utility.

In addition, under Section 39.158, an owner of electric generation facilities that offers electricity for sale in the state and proposes to merge, consolidate or otherwise become affiliated with another owner of electric generation facilities that offers electricity for sale in the state must obtain the approval of the commission before closing if the electricity offered for sale in the power region by the merged, consolidated or affiliated entity will exceed 1% of the total electricity for sale in the power region. In order to approve a transaction, in addition to the above, the PUC must determine that the transaction would not result in a violation of Section 39.154, which prohibits a power generation company from owning or controlling more than 20% of the installed generation capacity available to serve a specific power region. If the commission finds that the transaction as proposed would violate Section 39.154, the PUC may conditionally approve the transaction provided that they sufficiently modify the proposal to mitigate any potential market power abuses. The approval must be requested at least 120 days before the date of the proposed closing.

Prior to Sept. 1, 2017, the PUC was required to rule on a proposed transaction within 180 days "after the commission receives the relevant report." If the commission had not made a determination before the 181st day, the transaction was considered approved. However, Senate Bill 735, which became effective Sept. 1, 2017, allows the PUC to extend this deadline by up to 60 days "if the commission determines the extension is needed to evaluate additional information, to consider actions taken by other jurisdictions concerning the transaction, to provide for administrative efficiency, or for other good cause. If the commission has not made a determination before the expiration of the deadline provided by or extended under this subsection, the transaction is considered approved."

Completed mergers

In 1997, Southwestern Public Service Co., or SWPS, and Public Service Company of Colorado merged to form New Century Energy Inc., or NCE, and in 2000, NCE and Northern States Power merged to form Xcel Energy. The PUC adopted merger-related agreements under which SWPS was required to reduce rates by $17.2 million in two steps: a $4.8 million reduction, reflecting Texas jurisdictional merger-related cost savings, effective following approval of the 2000 merger and a $12.4 million reduction coincident with implementation of retail choice. The second-step reduction was not implemented due to a legislative ban on retail access implementation in SWPS' territory (see the Electric regulatory reform/industry restructuring section).

In 2009, SWPS entered into an agreement to sell certain distribution assets in Lubbock, Texas, to municipal utility Lubbock Power & Light for $87 million. The PUC approved the sale in early 2010.

In 2000, Central and South West Inc. and American Electric Power Company, Inc., or AEP, merged. The PUC approved a merger-related settlement under which AEP Texas Central Co., or TCC, Southwestern Electric Power Company, or SWEPCO, and AEP Texas North Co., or TNC, implemented base rate reductions totaling $52.7 million, $16.1 million and $15.6 million, respectively, to flow to customers related jurisdictional cost savings. TCC was required to divest 1,604 MW of generation capacity; the divestiture occurred as part of the electric industry restructuring process, and the proceeds were used to offset stranded costs. In 2002, AEP divested its retail businesses in TCC's and TNC's service territories to Centrica PLC.

In 2016, the PUC approved the merger of TCC and TNC to form AEP Texas Inc.; the transaction closed shortly thereafter. AEP Texas continues to have two separate divisions, the central division and north division, and maintain separate rates for each of the transmission and distribution units. Until the effective date of new rates established in its next base rate case, AEP Texas is to provide customers fixed rate credits aggregating to $0.63 million per year to flow to ratepayers savings expected from lower debt issuance costs — AEP Texas is to file its next rate case by May 1, 2019, under the PUC's rate case rules (see the Rate case timing/interim procedures section). The company will also be required to submit a yearly compliance filing detailing the amount of debt it issued in the prior year and provide customers additional "rate credits equal to 90% of 0.2% of that total debt issuance." In addition, the companies were required to obtain confirmation from the Federal Energy Regulatory Commission that the transaction will not alter the manner in which transmission prices are set for the companies, as established by the PUC's 1999 order approving the merger of AEP and Central and South West.

In 2000, Texas-New Mexico Power Co., or TNMP, parent TNP Enterprises was acquired by ST Acquisition Corp. In a related proceeding, the PUC approved a settlement under which: (1) TNMP was required to maintain investment grade bond ratings; (2) TNMP agreed to cap its leverage ratio at 65% through the end of 2001, and at 70% through 2003; (3) TNMP's dividends to Enterprises were limited to no more than TNMP's cash flow from operations, less cash flow from investing activities for each quarter; (4) Enterprises committed to devote $23 million of annual capital spending to the TDU through 2003; (5) TNMP's regulated rates were to be set assuming an investment-grade debt rating regardless of actual bond ratings; (6) TNP agreed to include provisions in its debt covenants that stated that its debt is non-recourse to TNMP; (7) TNMP was precluded from investing in businesses that were not engaged solely in the provision of utility services in the U.S. or Mexico; (8) TNMP was required to notify the commission of any changes in rating agency outlook for its debt securities; and, (9) TNMP agreed that it would reflect mitigation of $60 million of stranded costs through accelerated depreciation in its 2001 unbundled cost-of-service filing and subsequent stranded-cost true-up.

In 2005, PNM Resources Inc. acquired Enterprises, and, as a result, TNMP and affiliate retail electric provider FirstChoice Power became subsidiaries of PNM Resources. Under a merger-related agreement approved by the PUC, TNMP reduced its Texas retail electric distribution rates by $13 million, and rates were frozen through 2007. The agreement specified that TNMP would be authorized an ROE based upon the higher of its actual credit rating at the time of filing or the lowest investment-grade credit rating in any rate case filed prior to Jan. 1, 2009. In addition, in 2005, TNMP implemented a rate credit designed to return to Texas ratepayers $6 million of merger synergy savings over the 24 months following the close of the transaction. TNMP also agreed that it would not seek to recover through retail rates any transactions costs or any related goodwill or intangible assets resulting from the transaction. The company also agreed to comply with enhanced customer service performance standards that may include customer specific penalties for non-compliance.

In 2010, the PUC approved a stipulation thereby authorizing the transfer of control of Cap Rock Energy Inc. to Sharyland Distribution & Transmission Services LLC, or SDTS. By way of background, SDTS was formed in 1998 to provide retail electric service to the community of Sharyland Plantation in McAllen, Texas. SDTS is a delivery-only company within the Electric Reliability Council of Texas, or ERCOT, that has no generation assets and does not participate in the retail electric-provider market in Texas. Cap Rock was established as a cooperative in 1994 and became an investor-owned utility in 1998. SDTS was owned by a consortium of investors including Hunt Consolidated. At the time of the transaction, two of Cap Rock's four divisions were located in ERCOT, and two were located in the Southwest Power Pool. The approved stipulation called for the parties to investigate transferring the non-ERCOT territories to ERCOT and implementing retail competition in the Cap Rock service territories. The settlement also included provisions prohibiting the company from recovering transaction costs, goodwill or intangible asset costs from ratepayers and requiring the company to implement management efficiency proposals identified in a 2007 audit, maintain existing employee safety and reliability standards and refrain from extending an existing power sales agreement under which Cap Rock secures all of its power supply needs from SWPS; the agreement expired Dec. 31, 2013. The transaction closed in late 2010, and the legacy service territories are known as the McAllen division, with the newly acquired territories known as the Sharyland Utilities division. In 2011, the PUC approved a plan to transfer all non-ERCOT territories of the former Cap Rock to ERCOT by Jan. 1, 2014, and in 2012, the PUC approved a plan to transition these territories to retail competition in May 2014 (see the Electric regulatory reform/industry restructuring section).

In 2008, the PUC approved a settlement related to the leveraged buyout, or LBO, of TXU Corp., then the parent of what is now Oncor Electric Delivery, by a consortium of private investors led by Kohlberg Kravis Roberts & Co. and TPG Inc. PUC approval of the LBO was not required prior to completion of the transaction, and the deal closed in October 2007. The new company became known as Energy Future Holdings Limited Partnership, or EFH.

Under the approved agreement, Oncor was required to provide ratepayers with a $72 million one-time credit, and the PUC agreed to dismiss a then-pending Oncor rate investigation. Oncor was required to write-off $35 million of storm-related costs and roughly $21 million of restructuring-related regulatory assets. Through 2012, dividends paid by Oncor to the parent company were limited to "an amount not to exceed Oncor's net income, subject to certain adjustments." In addition, Oncor agreed to capital spending of at least $3.6 billion over the five-year period ending 2012. Oncor was required to comply with certain reliability and customer-service standards and submit annual reports to the PUC regarding compliance with all of these commitments.

Corporate governance-related commitments included: (1) Oncor's use of a separate and distinct logo from the parent and unregulated affiliates, a separate board and separate office facilities; (2) Oncor being prohibited from backing any new debt issued in conjunction with the transaction or thereafter; (3) Oncor maintaining its debt ratio "at or below the debt-to-equity ratio established from time to time by the Commission for ratemaking purposes," and limiting dividend payments to the parent if such payments would cause the debt ratio to rise above 60%; (4) maintaining annual capital expenditure levels at Oncor at or above then-current levels; (5) EFH expending at least $200 million over the five years following the close of the transaction on demand-side management programs; and (6) Oncor supporting "negotiated commitments" with interested parties concerning safety and reliability.

EFH ultimately held an 80% stake in Oncor, while 20% was held by an independent third party, Texas Transmission Holdings Corp. EFH filed for protection under the U.S. bankruptcy code in 2014. Even though Oncor was ring-fenced, the sale of the utility, subject to approval by the PUC, became part of EFH's bankruptcy reorganization plan. Three unsuccessful attempts (see the Terminated transactions section below) to acquire EFH's stake in Oncor were proposed before the PUC finally approved Sempra Energy Inc.'s acquisition of EFH's ownership share — discussed in more detail below.

While proceedings related to the sale of EFH's stake in Oncor were pending, in October 2017 the PUC approved a transaction under which Oncor would acquire Sharyland's distribution businesses in exchange for certain of Oncor's transmission assets. The transaction closed on Nov. 9, 2017. Oncor was required to achieve a capital structure with a 42.5% equity ratio by Nov. 27, 2017, or the company would have to accrue a regulatory liability reflecting the resulting revenue requirement difference. Oncor did not achieve the target equity ratio until May 4, 2018. Oncor was ultimately required to refund $6 million of related over-collections to ratepayers.

The Oncor/Sharyland asset swap was completed while the PUC was considering an Aug. 20, 2017, proposal by Sempra Energy to acquire EFH and its stake in Oncor. The proposal was supported by Elliott Management, EFH's largest creditor, who successfully blocked a prior proposed acquisition of EFH. The FERC approved the transaction in December 2017. On Feb. 26, 2018, the U.S. Bankruptcy Court gave final approval for the transaction. The PUC unanimously approved the transaction on March 8, 2018, subject to the conditions outlined in a settlement, and the deal closed on March 9, 2018.

Pursuant to the approved settlement, Oncor's post-transaction board of directors was required to consist of 13 members, as follows: seven independent directors as defined by the rules of the New York Stock Exchange; two designated by Sempra; two appointed by Texas Transmission Holdings and two officers of Oncor, initially Robert Shapard and E. Allen Nye Jr., who, no later than at the closing of the transaction, would become the chair of the Oncor board and CEO of Oncor, respectively.

Oncor is to make minimum aggregate capital expenditures equal to at least $7.5 billion from Jan. 1, 2018, through Dec. 31, 2022, with an incremental $35 million on cybersecurity investment. Sempra was required to provide its proportionate share of equity necessary for Oncor to achieve a 42.5% equity ratio, as required by settlements concerning Oncor's asset swap with Sharyland

In addition, Oncor is required to provide bill credits to customers in an amount equal to 90% of any interest-rate savings achieved due to any improvement in its credit ratings or market spreads compared to those as of June 30, 2017, until final rates are set in the next Oncor base rate case — the case is to be filed no later than Oct. 1, 2021. In addition, beginning one year after closing, Oncor is to provide bill credits to its customers equal to 90% of any synergy savings achieved until final rates are set in Oncor's base rate proceeding, at which time all synergy savings achieved would be reflected in Oncor's rates.

Oncor is to refrain from filing a rate case for at least two years following PUC approval of the settlement in this case, and Oncor will not seek recovery of any costs associated with EFH's bankruptcy. In addition, none of the transaction or transition costs will be borne by Oncor's customers, nor will Oncor seek to include transaction costs in rates.

With respect to corporate governance, Sempra is to extinguish all debt that resides above Oncor. Sempra is to ensure that, as of the closing of the transaction, Oncor's credit ratings at all three major ratings agencies will be at or above Oncor's credit ratings as of June 30, 2017, and if the credit rating does fall below this level, Oncor will suspend payment of dividends or other distributions, except for contractual tax payments, until otherwise allowed by the PUC.

In addition, Oncor's debt-to-equity ratio must remain in compliance with the debt-to-equity ratio established by the PUC for ratemaking purposes. Oncor will be precluded from the payment of dividends or other distributions if such payments would cause Oncor to violate this condition.

Oncor will refrain from participating in any cross-company debt, lending arrangements or credit facilities, nor will it pledge its assets for any affiliated entity. Oncor Holdings is to be maintained between Sempra and Oncor, and Sempra is to retain at least a 51% share of Oncor for a minimum of five years.

In addition, Oncor will maintain its separate headquarters and management in Dallas, and Oncor will continue to operate solely within the state of Texas as a public utility subject to the continuing jurisdiction of the PUC. Moreover, for two years after closing, each worker employed by Oncor on the closing date will be accorded base salary, incentive compensation and benefits on terms or wage rate that are no less favorable than those provided to the employee immediately prior to the closing date. Oncor is to honor all existing collective bargaining agreements.

In February 2018, the PUC approved a transaction whereby ECP ControlCo, LLC proposed to merge its indirect, wholly-controlled subsidiary, Volt Merger Sub, Inc, with Calpine Corporation, an owner of generation facilities in Texas. The main issue in the transaction was related to generation concentration within ERCOT. Following the transaction, Calpine became an indirect, wholly-controlled subsidiary of ECP and various passive investors. ECP is an indirect owner of one generating facility in Texas, — the Big Spring wind generation facility. ECP also controls an indirect subsidiary, Terawatt Holdings, LP, which currently owns approximately 14.88% of the total outstanding common shares of the common stock in Dynegy. ECP stated that by the closing date of the transaction, Terawatt would divest its ownership down to less than 10% of the outstanding shares of Dynegy common stock. Dynegy indirectly owns and controls 4,353 MW of generation in ERCOT. VoltSub is a direct subsidiary of VoltParent, and is wholly-owned by ECP and certain passive limited partner investors. Two of those partner investors, Access Industries, Inc. and Canada Pension Plan Investment Board, or CPPIB, have indirect ownership interests in other generating facilities in Texas. Access owns an 18% indirect share in Equistar Chemicals LP, which owns a 40 MW qualifying facility in ERCOT. CPPIB has an indirect, passive ownership interest in an affiliate of Quantum Utility Generation LLC, which, through one or more affiliates, is currently developing four generating facilities in ERCOT that are anticipated to commence operations within the next 12 months. Thus, ECP, Access, CPPIB, Calpine, and their respective affiliates own no more than 11,219 MW of generation capacity located within the ERCOT region. In addition, Calpine owns and controls generating capacity in other power regions. As the quantity of generating capacity in other power regions exceeds the maximum capacity of the DC ties from the Eastern Interconnection into ERCOT, ECP sets the value of the installed generation capacity in other regions capable of being delivered into ERCOT at that maximum capacity, which is 820 MW. Combined with the total capacity of all parties that is located in the ERCOT region, ECP calculated the installed generation capacity capable of delivering energy into ERCOT to be either 11,826 MW or 12,039 MW. Based on the total installed capacity in ERCOT of 93,132 MW, ECP calculated the combined share of capacity to be approximately either 12.7% or 12.9%, which would not violate commission rules regarding the percentage of generation within ERCOT one entity can control.

In April 2018, the PUC approved the proposed merger of Vistra Energy Corp. and Dynegy Inc., under which Vistra was the surviving entity. Both own power generation companies, or PGCs, that sell power into the ERCOT market; Vistra's subsidiaries own 13,043 MW of installed capacity in ERCOT and Dynegy's PGCs own 4,042 MW. The PUC has authority over the proposed transaction under Section 39.158 of Public Utility Regulatory Act, or PURA, since Vistra subsidiary Luminant Generation Company offers more than 1% of the total MWHs offered for sale in ERCOT. The applicants stated that the combined entity will not violate Section 39.154 of the PURA, which prohibits a single entity from owning more than 20% of the installed capacity in ERCOT. Luminant noted the combined company would control between 16,354 MW and 17,896 MW, or an 18.7% to 20.7% ERCOT market share. The differences in the combined capacity totals and associated percentages depend on whether Vistra sells all or none of the units at the Graham, Stryker Creek and Trinidad generating facilities, and whether 820 MW of Dynegy-owned capacity outside of ERCOT capable of import into the grid operator is included in the companies' combined market share. Vistra is also marketing the coal-fired, 1,150-MW Big Brown facility, which will be retired in February 2018 if not sold. The PUC staff had recommended that the commission find that the merger would cause the combined entity would exceed the 20% statutory requirement imposed by state law, but indicated that the commission has authority to approve the transaction with the adoption of reasonable modifications to mitigate potential market power abuses, such as divestiture of at least 1,281 MW of installed generation capacity in ERCOT to get below the 20% threshold. However, the PUC found that the combined entity would not exceed the 20% threshold since Vistra's generation capacity outside of ERCOT cannot be imported into ERCOT over the existing facilities. The FERC also approved the transaction in April 2018.

Terminated transactions

In 2008, PNM Resources entered into an agreement to purchase Cap Rock Energy from Continental Energy Systems, a consortium of private investors, as part of a deal under which Continental acquired TNMP's New Mexico natural gas operations. However, PNM and Continental later announced that the sale of Cap Rock had been terminated.

In 2012, the PUC conditionally approved a proposal by Entergy Texas to cede control of its transmission facilities to the Midcontinent Independent System Operator, or MISO, regional transmission organization. The proposal was part of Entergy's plan to transfer control of the transmission assets of all of its operating subsidiaries to MISO in December 2013 in conjunction with a proposed spin-off of the assets and their subsequent acquisition by ITC Holdings. The companies withdrew the proposed divestiture to ITC in December 2013, following rejection of the transaction by the Mississippi Public Service Commission.

In 2016, the PUC conditionally approved the acquisition of Oncor by a consortium of investors, led by Hunt Consolidated Inc. Hunt, which also owns Sharyland Utilities, and its consortium of investors indicated that they would restructure Oncor into a real estate investment trust, or REIT. The proposed transaction was part of Oncor parent EFH's bankruptcy reorganization plan that was approved by the U.S. Bankruptcy Court.

Among the conditions were provisions designed to flow the tax benefits of the proposed REIT structure for Oncor to ratepayers, require PUC review and approval of the specifics of the lease transactions between the operating company and the asset company, and require the operating company and asset company to file joint rate cases. Certain parties sought rehearing of the commission order, and the ensuing litigation led certain participants in the bankruptcy reorganization plan to withdraw from the deal. In May 2016, the proceeding was terminated by the PUC at the parties' request, and Hunt withdrew the offer.

In April 2017, the PUC rejected an agreement under which NextEra Energy Inc. was to acquire EFH and its 80% stake in Oncor. The PUC found that the "sole tangible and quantifiable benefit" offered by NextEra is a commitment to share 90% of the interest-rate savings on Oncor's cost of debt with ratepayers until new rates reflecting the lower debt costs are implemented. The PUC opined that other benefits cited by NextEra had either not been quantified or are not exclusive to this transaction. In addition, the PUC found that the existing ring fence, which NextEra sought to remove, was "critical in protecting Oncor from the bankruptcy of its indirect parent company. Under the proposed transactions, a robust ring fence is still necessary to protect Oncor if NextEra Energy or one of its subsidiaries were to file for bankruptcy." The PUC denied subsequent motions for rehearing, thus affirming its April order.

In July 2017, a deal was announced under which Berkshire Hathaway Energy was to acquire EFH and the majority stake in Oncor. Review by the bankruptcy court and the PUC was required. A shell docket was opened for the PUC review, but no formal filing was submitted. Berkshire withdrew its offer following the announcement of a competing offer by Sempra Energy, which was ultimately successful.

In October 2017, the PUC dismissed without prejudice, a transaction under which NextEra was to acquire Texas Transmission Holdings Corp.'s, or TTHC's, 19.75% share of Oncor. The sale agreement had been reached while NextEra's proposed acquisition of EFH and Oncor was pending. NextEra claimed that this transaction was separate and should be reviewed as such. The PUC staff opined that NextEra and TTHC did not have standing to apply for a change of even partial ownership of Oncor without Oncor as an applicant. The companies had been expected to file a renewed application, with Oncor participating; however, TTHC terminated the deal.

Pending transactions

On Nov. 30, 2018, Oncor, its majority owner Sempra Energy, Sharyland Distribution & Transmission Services LLC, or SDTS, and Sharyland Utilities LP, or SU, filed for approval of a series of transactions that would result in the reorganization of various delivery assets within ERCOT. Under the proposal, Sharyland Distribution and Transmission, or SDTS, would become a wholly owned subsidiary of Oncor that would own transmission and distribution assets now held by SDTS, SU and InfraREIT Partners LP in Central, North and West Texas. These assets would be known as The North Texas Utility. Sempra would acquire a 50% stake in SU, which would retain existing assets in South Texas, including those obtained as part of an asset swap between InfraREIT and SDTS to divide their assets geographically. SU would be known as The South Texas Utility. The real estate investment trust, InfraREIT Inc., that now holds InfraREIT Partners, SDTS and SU would be dissolved, and SU's interest in SDTS, as well as certain individual assets, would be eliminated. InfraREIT is externally managed by Hunt Utility Services LLC, an affiliate of Hunt Consolidated Inc., a diversified holding company based in Dallas, Texas, and managed by the Ray L. Hunt family. Oncor, InfraREIT, InfraREIT Partners and two wholly owned subsidiaries of Oncor entered into an agreement under which Oncor will acquire InfraREIT and InfraREIT Partners and, as a result, will own and operate all of SDTS' post-transaction assets. Final PUC action is required by May 29, 2019, but the deadline may be extended by up to 60 days. (Section updated 4/23/19)

Electric Regulatory Reform/Industry Restructuring

Enabling legislation

Pursuant to 1999 legislation, retail competition was implemented for generation service in 2002, in the service territories of integrated electric utilities operating within the Electric Reliability Council of Texas, or ERCOT. The affected utilities included AEP Texas, Oncor Electric Delivery Co., CenterPoint Energy Houston Electric Inc., or CEHE, and Texas-New Mexico Power Co., or TNMP, all of which were required to unbundle their integrated operations into separate affiliated retail electric providers, or AREPs, power generation companies and transmission and distribution companies, or TDUs.

The legislation provided for a transition period to phase in the new market structure and a true-up mechanism through which the restructured utilities would recover stranded and certain other costs resulting from the transition. These costs were recoverable through the implementation of a competition transition charge or the issuance of securitization bonds.

Retail competition has not been implemented in the service territories of El Paso Electric Co., Southwestern Public Service Co. or Southwestern Electric Power Company. The PUC approved a retail competition pilot program for large-volume customers of Entergy Texas in 2012. In 2013, following PUC approval Entergy transferred control of its transmission assets to the Midcontinent Independent System Operator regional transmission organization. In 2014, retail competition was implemented in the service territories of Sharyland Utilities Distribution and Transmission; these businesses are now owned by CEHE.

Default service

Residential and small commercial customers who did not affirmatively select a generation provider were served by the AREP under capped "price-to-beat" rates through 2006. Since then, provider-of-last-resort service has been available only to customers who are disconnected from their selected provider. Such service is intended to be temporary, and default suppliers are designated for each utility service territory by the PUC, subject to rules that are revised periodically. Generally, such suppliers are permitted to charge prices that include a premium over prevailing market rates. Customers that do not affirmatively select an REP are assigned to one by the commission.

Resource adequacy

While the generation market is competitive within ERCOT, the PUC is charged with ensuring that there are sufficient resources available as part of its market oversight authority.

Several proceedings have been initiated in recent years to address resource adequacy and market structure issues. In 2014, following a series of price spikes in the wholesale power market, the PUC opened Docket No. 40000 to consider options such as imposing reserve margin requirements on generation suppliers and moving from an energy-only market to an energy and capacity market. The proceeding went dormant when market prices normalized and began to fall in the wake of the shale gas boom.

In 2015, the PUC opened Docket No. 45572 to review the operation of ERCOT's Operating Reserve Demand Curve, which was implemented in 2014. In the context of this proceeding, in May 2017, Calpine Corp. and NRG Energy Inc. filed a report entitled Priorities for the Evolution of an Energy-Only Market in ERCOT. The PUC initiated a separate proceeding (Docket No. 47199) to review the report. In comments filed on Sept. 15, 2017, the ERCOT market monitor endorsed a change to a real-time co-optimization, or RTC, framework, in order to find the most efficient way to procure energy and ancillary services every five minutes in ERCOT's real-time market. The process already takes place in the day-ahead market, or DAM, but capacity from resources selected in that market to provide ancillary services including responsive reserves, regulating reserves and offline non-spinning reserves is set aside and unavailable to provide energy in the real-time market. In comments filed on Sept. 29, 2017, various parties objected to the proposals stating that they were too costly. On March 8, 2018, the PUC directed ERCOT to implement rule changes that would remove reliability-must-run and reliability-unit-commitment capacity from the calculation of the market's available operating reserves. Proponents of doing so have argued that units committed to providing service through out-of-market actions distort price formation. However, the PUC declined to make any further changes to the ERCOT pricing paradigm until performance data is available following the summer 2018 peaking season (see the Integrated resource planning section).

Separately, in September 2017, the PUC voted to alter rules governing reliability must-run and must-run alternative service in the state's wholesale power market. As a stop-gap measure, ERCOT enters into out-of-market contracts with generators if the grid operator determines that those resources are necessary to provide voltage support, stability or management of localized transmission constraints and that market solutions to provide those services do not exist.

The rule change, which became effective Jan. 1, 2018, adjusted the notice requirements and timeline for suspending operation of generation resources, granted ERCOT the discretion not to enter into reliability must-run, or RMR, contracts, required ERCOT board approval of ERCOT staff recommendations regarding RMR and must-run alternative, or MRA, service "as a check on the judgement of ERCOT's staff [that] better safeguards the public interest," and required the refund of payment for capital expenditures related to RMR and MRA service under certain circumstances.

In April 2018, Invenergy LLC provided the PUC the results of a report the firm had commissioned from PA Consulting Group Inc., "The Long-term Impacts of Marginal Losses on Texas Electric Retail Customers." The report suggested that including the addition of marginal losses to locational marginal price formation would not be beneficial, despite generator assertions to the contrary. The PUC directed ERCOT to study the benefits of implementing RTC and marginal losses in the ERCOT wholesale market. A report issued in June 2018, concluded that there would be significant operational benefits from the implementation of RTC, including more timely procurement of additional ancillary services when necessary, more effective congestion management, a reduction in manual actions by operators and an improved management of resource-specific capabilities in assigning and deploying ancillary services.

The PUC opened a separate proceeding (Docket No. 48540) to consider the RTC proposal in July 2018, and the parties filed comments in October. The PUC discussed the issues at its Jan. 17, 2019 meeting and directed ERCOT to begin the process to implement RTC, report back to the Commission with "a high level implementation plan and timeline, and set aside "any favorable variance in revenues" for fiscal years 2018 and 2019, and await further discussion on whether such favorable financial variance shall be used to fund the project to implement RTC. Parties are to file comments on implementation issues in April 2019.

Interconnection issues

In 2015, legislation was enacted to bar any entity, including investor-owned or municipal utilities from interconnecting a facility to the ERCOT grid that enables additional power to be imported into or exported out of the grid unless that entity obtains a certificate of public convenience and necessity, or CPCN, from the PUC. A CPCN must be tendered to the PUC 180 days prior to seeking an order from the Federal Energy Regulatory Commission related to the interconnection. In reviewing the CPCN, the PUC must assess whether the interconnection proposal is consistent with the public interest as it pertains to ratepayers in Texas. The law does not apply to facilities that were operating as of Dec. 31, 2014.

A rulemaking is ongoing regarding governance, performance and funding of the Smart Meter Texas, or SMT, portal. The portal is an interoperable, web-based information system that stores electric usage data recorded by advanced meters in increments of 15-minute intervals or shorter and provides secure access to that data to customers, retail electric providers, persons authorized by customers to have access to that data and ERCOT. In December 2016, the PUC approved amendments to its existing rules pertaining to interconnection agreements involving distributed generation owners. The amendments are designed to allow an end-use customer to either be a party to an interconnection agreement with the incumbent utility or select any of the following types of entities to be the non-utility party to the interconnection agreement: the owner of the distributed generation, or DG, facility, an owner of rights to energy produced from the DG facility or the owner of the premises at which the DG facility is located.

Stranded cost recovery

In 2006, the PUC authorized AEP Texas to recover $1.476 billion of net true-up balances. The PUC subsequently adopted a settlement calling for securitization of $1.721 billion of stranded and other qualified costs. Following lengthy appeals, in 2011 the PUC adopted a settlement authorizing the company to recover $800 million of incremental stranded costs, including interest. In 2012, the PUC authorized the company to securitize the remaining stranded costs (see the Securitization section).

Oncor had estimated that it would have $3.7 billion of stranded costs. Following a settlement under which Oncor agreed to forego recovery of stranded costs, the PUC authorized Oncor to issue $1.3 billion of securitization bonds and fixed Oncor's stranded costs at zero.

In 2004, the PUC authorized CEHE to recover $2.301 billion, including interest, of stranded costs. In 2005, the PUC authorized the company to issue roughly $1.851 billion of securitization bonds, with the remainder of its stranded costs to be recovered through a competition transition charge. Following appeals, in 2011 the PUC adopted a settlement authorizing CEHE to recover $1.7 billion of incremental stranded costs, including interest; in a separate proceeding, the PUC approved the company's proposal to securitize the incremental stranded costs (see the Securitization section).

In 2004, the PUC authorized TNMP to recover $71.5 million of net true-up balances, excluding interest. On reconsideration, in

2006 the PUC adopted a settlement permitting TNMP to implement a competition transition charge designed to recover $136.9 million of net stranded costs and other true-up balances, including interest accrued through June 30, 2006.

Retail competition was also implemented in the service territory of what is now known as Sharyland Distribution & Transmission Services, or SDTS, which was formed in 1998 to provide retail electric service to the community of Sharyland Plantation in McAllen, Texas. In 2010, SDTS acquired control of Cap Rock Energy (see the Merger activity section). At the time of the transaction, two of Cap Rock's four divisions were located in ERCOT and two were located in the Southwest Power Pool, or SPP. The PUC directed the company to file plans to transfer the SPP territories to ERCOT and implement retail competition for all of the former Cap Rock territories, which now do business as Sharyland Utilities.

In 2011 the PUC approved a plan to transfer all of the former Cap Rock territories to ERCOT by Jan. 1, 2014, and in 2012 the PUC approved a plan to transition these territories to retail competition effective May 1, 2014. Under the plan, all customers that did not select a competitive supplier were assigned to a default supplier, which for the Sharyland Utilities division were selected by the PUC staff, ERCOT and other stakeholders. Default service is provided on a month-to-month, market-priced basis.

On March 15, 2018, the PUC issued an order approving a proposal by Lubbock Power & Light to move 470 MW of its estimated 600-MW load from the SPP to ERCOT beginning June 1, 2021. Southwestern Public Service currently supplies power to Lubbock with one short-term agreement for 470 MW through May 30, 2021, and a long-term agreement serving the remainder through 2044. The City had reached agreement with most of the major stakeholders. The agreement calls for Lubbock to pay $22 million a year for five years to ERCOT wholesale transmission customers, Lubbock to make a one-time $24 million hold-harmless payment to Southwestern upon the date of integration into ERCOT that is to be credited to customers and Lubbock to take no action that would cause the Federal Energy Regulatory Commission to assert jurisdiction over ERCOT.

Non-traditional technologies

In February 2018, the PUC opened a rulemaking (Docket No. 48023) to address the use of "non-traditional" technologies in delivery service. On Sept. 7, 2018, the PUC staff requested that interested parties provide comments by Nov. 2, 2018, on such issues as what benefits non-traditional technologies, such as energy storage could provide as a potential cost-effective solution to reliability issues on a utility's transmission or distribution system, whether a utility can legally own such technology, what market-based alternatives exist and what impediments are there to using non-traditional technology. The PUC Competitive Markets division issued a memorandum in January 2019 highlighting issues raised. It appears that the docket has been placed on hold in light of pending legislation that would address these issues (see the Legislation section). (Section updated 4/23/19)

Gas Regulatory Reform/Industry Restructuring

Local gas distribution companies are regulated by the Railroad Commission of Texas. (Section updated4/23/19)

Securitization

State law permits the PUC to utilize securitization for recovery of stranded costs associated with electric industry restructuring and for major storm-related service restoration costs.

Stranded costs

The 1999 electric restructuring law authorized upfront securitization of up to 100% of regulatory assets and 75% of non-mitigated stranded costs following a PUC finding that such securitization would reduce total costs charged to customers. During 2000, several of the investor-owned utilities filed for securitization of regulatory assets.

The PUC authorized AEP Texas to issue $797 million of bonds to securitize regulatory assets and other qualified costs. The bonds were issued in 2002.

The PUC also authorized Oncor Electric Delivery to issue $362 million of bonds to securitize $345 million of regulatory assets and $17 million of other qualified costs; Oncor had sought to securitize $1.6 billion. Following appeals, in 2002 the PUC adopted a settlement that authorized Oncor to issue $1.3 billion of bonds in two steps; Oncor issued $500 million of bonds in August 2003 and $790 million in June 2004.

The PUC approved a settlement, thereby authorizing CenterPoint Energy Houston Electric, or CEHE, to issue $750 million of bonds to securitize $740 million of regulatory assets and $10 million of issuance costs. CEHE issued $749 million of bonds in

October 2001.

The utilities were also permitted to seek additional securitization to address recovery of any generation-related stranded costs approved by the PUC as part of legislatively mandated "true-ups." Legislation enacted in 2007 allowed other restructuring-related balances that were initially approved for recovery through a competition transition charge, or CTC, to be securitized as well.

In 2005, the PUC approved CEHE's request to securitize $1.8 billion of stranded costs, which included interest on the recoverable stranded cost balance that accrued through May 31, 2005, with the securitizable amount to be updated to reflect interest through the date of issuance; CenterPoint issued $1.85 billion of bonds in December 2005.

In 2006, the PUC adopted a settlement authorizing AEP Texas to issue bonds totaling $1.721 billion, including interest on the stranded cost balance through Aug. 30, 2006. The company issued $1.74 billion of bonds in September 2006.

In 2007, CenterPoint filed to issue $551.3 million of bonds, representing the company's as-yet-unrecovered CTC balance. The parties subsequently reached an agreement calling for the securitizable balance to be reduced to $511 million, and the PUC ultimately approved the agreement. CenterPoint issued $488 million of bonds in February 2008, representing its updated, then-unrecovered CTC balance.

Following appeals of the PUC's 2004 stranded-cost-true-up order for CEHE, in 2011 the PUC authorized the company to securitize $1.7 billion of incremental stranded costs, including interest. The bonds were issued in January 2012. Following appeals of the PUC's 2006 stranded-cost-true-up order, in 2012 the PUC authorized AEP Texas to securitize $800 million of incremental stranded costs. The bonds were issued in March 2012.

Storm costs

Legislation enacted in 2006, authorized utilities to seek PUC approval to securitize restoration costs associated with Hurricane Rita. The PUC subsequently approved a settlement allowing Entergy Texas Inc. to recover $381.2 million of Hurricane Rita-related deferrals. The company issued $330 million of bonds in June 2007.

In 2009 legislation was enacted authorizing the PUC to allow the utilities to securitize restoration costs associated with Hurricanes Gustav and Ike, as well as any future major storms.

In 2009 the PUC adopted a settlement providing for CEHE to recover $663 million of storm restoration costs, plus company charges and issuance costs; $664.8 million of bonds were issued in November 2009. The PUC also adopted an agreement calling for Entergy to recover $566.4 million of storm-related costs and later adopted a settlement allowing Entergy to issue securitization bonds totaling $544.9 million; Entergy issued $545.9 million of bonds in November 2009.

On Aug. 7, 2018, AEP Texas Inc. filed (Docket No. 48577) for a PUC determination that $415 million of restoration costs associated with Hurricane Harvey and certain other storms accrued through April 30, 2018, are eligible for recovery. In addition, the company seeks authorization to accrue carrying charges on the costs at the company's weighted average cost of capital. On Nov. 28, 2018, the parties filed a settlement quantifying reasonable restoration costs, net of insurance proceeds, at $369 million. Certain of these costs would be deferred with carrying costs and would be eligible for securitization. The PUC approved the settlement on Feb. 17, 2019. On March 8, 2019, the company filed (Docket No. 49308) for approval to securitize $225 million of the costs, plus $4.6 million of up front issuance costs. (Section updated 4/23/19)

Adjustment Clauses

For electric utilities that have not implemented retail competition, fuel and purchased power costs are recovered through a separate fuel factor, the level of which is established in base rate cases. Between base rate cases, the fuel factor may be adjusted, following hearings, based on projected fuel costs for the period the fuel factor will be in effect, subject to true-up. Fuel reconciliations occur at least every three years but no more than every 12 months.

Capacity costs associated with purchased power are recovered through base rates, while energy costs are reflected in the fuel factor. Under- or over-recoveries are deferred, with interest, for recovery over a subsequent 12-month period. El Paso Electric Co., or EPE, Southwestern Public Service Co., or SWPS, Southwestern Electric Power Company, or SWEPCO, and Entergy Texas Inc. have not implemented retail competition and continue to operate under the fuel factor mechanism. Pursuant to an August 2016 rate decision, EPE is to recover costs associated with obtaining renewable energy credits through the fuel factor.

For utilities that implemented retail competition, namely, AEP Texas Co., Oncor Electric Delivery Co., CenterPoint Energy Houston Electric Co., or CEHE, and Texas-New Mexico Power Co., or TNMP, and Sharyland Utilities, all customers' prices are set essentially at the retail electric providers' discretion. Such a provider must notify customers 45 days prior to a price change.

Fuel-cost-recovery issues are not applicable to transmission-only utilities such as Cross Texas Transmission LLC, Electric Transmission of Texas LLC, Lonestar Transmission LLC and Wind Energy Transmission of Texas.

Transmission charges

For the service territories in which retail competition has been implemented, transmission is functionally separate from distribution, and while transmission and distribution base rate cases are filed jointly, separate revenue requirements are identified for each function. In addition, transmission service providers, or TSPs, are permitted to file up to twice annually to implement rate changes to reflect new used and useful transmission facilities through the interim transmission cost-of-service, or TCOS, mechanism. TCOS mechanisms have been approved for CenterPoint, Oncor, TNMP and AEP Texas, as well as transmission-only utilities Cross Texas Transmission, Electric Transmission Texas, Lone Star Transmission, Sharyland Utilities and Wind Energy Transmission Texas. TCOS mechanism rates may be adjusted twice per year.

Transmission revenue requirements established through either base rates or the interim TCOS procedure are allocated among the distribution service providers, or DSPs, in accordance with PUC-approved, load-based allocation factors established under the commission's "transmission matrix." The DSPs are permitted to adjust rates twice annually to reflect changes in wholesale transmission costs assigned to the DSP. These changes flow through transmission cost recovery factors, or TCRFs, that are in place for AEP Texas, CEHE, Oncor and TNMP.

Utilities that have not implemented retail competition, EPE, Entergy, SWEPCO and SWPS, may file once annually between rate cases for adjustments to reflect new investment in transmission facilities. This procedure is also known as a TCRF mechanism. TCRF mechanisms have been in place for SWEPCO and SWPS for some time..

In a 2018 rate case, Entergy Texas proposed riders for the recovery of costs assigned to the company's retail business by the Federal Energy Regulatory Commission and to reflect the revenue requirement implications of deferred tax accounting on an ongoing basis that would encompass all such issues, not just those related to the 2017 federal tax overhaul that lowered the federal corporate tax rate to 21% from 35%. However, the controversial riders were withdrawn as part of a settlement resolving the case.

Delivery infrastructure

State law permits the utilities to recover costs associated with deployment of advanced metering technology through a separate, annually updated surcharge, and the PUC has approved such mechanisms when requested. Such riders are in place for CEHE, Entergy Texas, Oncor, AEP Texas and TNMP.

Pursuant to legislation enacted in 2011, the PUC may approve periodic distribution cost recovery factors, or DCRFs, for all electric utilities. Adjustments under the mechanism are limited to once per year, with no more than four adjustments permitted between comprehensive base rate cases. Rate changes approved under the mechanism must be applied on a systemwide basis, reflect the rate structure approved in the company's most recent base rate case and reflect changes in customer count and "the effects, on a weather-normalized basis that energy consumption and energy demand have on the amount of revenue recovered through the utility's base rates." The PUC may prohibit a utility from implementing a rate change under the mechanism if the commission determines that the utility is earning in excess of its authorized return prior to the adjustment. Amounts approved for recovery under the DCRF are rolled into base rates in a subsequent rate case, subject to a prudence review. In setting the DCRF revenue requirement, the PUC must utilize the rate of return specified in the company's most recent base rate case, provided the decision in that case was rendered within three years prior to the DCRF filing. Otherwise a 10% equity return is used. DCRFs have been approved for AEP Texas, CEHE, Entergy Texas, Oncor, Sharyland Utilities, SWEPCO and SWPS. EPE filed to implement a DCRF on March 28, 2019, as permitted by the PUC's December 2017 base rate case decision for the company.

Energy efficiency/conservation

The electric utilities are permitted to request recovery of costs associated with legislatively mandated (see the Integrated resource planning section) energy efficiency programs through a streamlined adjustment mechanism. AEP Texas, CenterPoint, El Paso Electric, Entergy, Oncor, SWEPCO, SWPS and TNMP each have such mechanisms in place.

Storm costs

The PUC has approved a rider that allows Entergy to recover variations in storm costs versus the levels included in base rates on a current basis.

Other

CEHE, Entergy and TNMP have adjustment clauses in place to reflect changes in municipal franchise fees. EPE has a rider in place to recover lost revenue associated with the provision of discounted service to military bases, while SWPS recovers lost revenue associated with the provision of discounts to state universities through a rider mechanism. (Section updated 4/23/19)

Integrated Resource Planning

While the retail generation business is subject to competition in the Electric Reliability Council of Texas, or ERCOT, service territories (see the Electric regulatory reform/industry restructuring section), the PUC retains jurisdiction over plants owned by the remaining vertically integrated utilities, and a competitive bidding process is mandated for new generation resources.

Energy efficiency

As per state law and PUC rules, since 2004 utilities have been required to institute energy efficiency and/or demand-side management programs designed to reduce annual demand growth by 10% versus forecast demand levels absent the programs. However, legislation enacted in 2011 directed each electric utility to annually "provide through market-based standard-offer programs or through targeted market-transformation programs, incentives sufficient for retail electric providers and competitive energy service providers to acquire additional cost-effective energy efficiency, subject to cost ceilings established by the PUC, for the utility's residential and commercial customers equivalent to not less than 30% of the electric utility's annual growth in demand" for these customer classes beginning in 2013.

Resource adequacy in ERCOT

Within ERCOT, the PUC is charged with ensuring that there are sufficient resources available as part of its market oversight authority. In 2011, the PUC initiated a proceeding (Docket No. 40000) to address resource adequacy issues in light of then-evolving environmental regulations and demand growth within ERCOT. Information and filings garnered in previous commission-initiated workshops on these issues were rolled into the new docket. Among the topics being addressed was a possible transition from an energy-only market within ERCOT to one that would also include a forward capacity market and/or the imposition of a mandatory reserve margin. As the PUC examined the issues surrounding resource adequacy, certain intermediate steps were taken. For example, the PUC increased the systemwide offer cap to $4,500/MWh from $3,000/MWh effective Aug. 1, 2012, and then to $5,000/MWh effective June 1, 2013; the cap rose to $7,000/MWh effective June 1, 2014, and to $9,000/MWh effective June 1, 2015. In addition, in 2013 the PUC adopted an operating reserve demand curve, or ORDC, to be implemented in ERCOT. In 2014, ERCOT filed a revised load forecast demonstrating a significant reduction in forecast peak load through 2023 and estimating that ERCOT would not fall below the existing 13.75% planning reserve margin until 2019. As a result, the discussions moved away from reforming the market structure within ERCOT and focused on the appropriateness of the PUC's current reliability standard used to set the reserve margin, namely a "1-in-10-year loss-of-load event" standard. The proceeding remains open but is largely inactive as other proceedings have been opened to address related issues.

In 2016, the PUC opened a new proceeding (Docket No. 45572) to review the operation and impacts of the ORDC in light of certain concerns with respect to changes in bidder behavior since the curve was instituted. That proceeding is also ongoing. The PUC is also reviewing ERCOT planning and system costs associated with renewable resources and new large DC ties in Docket No. 42647, inputs included in ERCOT capacity and demand calculations in Docket No. 41060, demand-response in Docket No. 41061 and reliability standards in ERCOT Docket No. 42302.

For the most part these dockets remain open but largely inactive. However, in May 2017, Calpine Corp. and NRG Energy filed a report entitled Priorities for the Evolution of an Energy-Only Market in ERCOT, and the PUC opened a new proceeding (Docket No. 47199) to address the report.

In comments filed in September 2017, the ERCOT market monitor endorsed a change to a real-time co-optimization framework in order to find the most efficient way to procure energy and ancillary services every five minutes in ERCOT's real-time market. The process already takes place in the day-ahead market, or DAM, but capacity from resources selected in that market to provide ancillary services, including responsive reserves, regulating reserves and offline non-spinning reserves, is set aside and unavailable to provide energy in the real-time market. In comments filed on Sept. 29, 2017, various parties objected to the proposals stating that they were too costly.

In March 2018, the PUC directed ERCOT to implement rule changes that would remove reliability-must-run and reliability-unit-commitment capacity from the calculation of the market's available operating reserves. Proponents of doing so have argued that units committed to providing service through out-of-market actions distort price formation. However, the PUC declined to make any further changes to the ERCOT pricing paradigm until performance data is available following the summer 2018 peaking season.

In April 2018, Invenergy LLC provided the PUC the results of a report the firm had commissioned from PA Consulting Group Inc., "The Long-term Impacts of Marginal Losses on Texas Electric Retail Customers." The report notes that recently some power generation owners have voiced concerns that the ERCOT market is not providing high enough power pricing to justify past and future investment decisions. These generation owners have advocated for several proposed market design changes, including the addition of marginal losses to locational marginal price, or LMP, formation. The report concludes that customers in Texas would be much better-off under the current market structure without the integration of marginal losses. The report opines that while an LMP approach may optimize physical efficiency, it would not necessarily optimize economic efficiency for Texas customers due to the unique structure of the Texas markets. The PUC directed ERCOT to study the benefits of implementing real-time co-optimization and marginal losses in the ERCOT wholesale market. The studies were completed by the end of June 2018.

In September 2017, the PUC voted to alter rules governing reliability must-run and must-run alternative service in the state's wholesale power market. As a stop-gap measure, the ERCOT enters into out-of-market contracts with generators if the grid operator determines that those resources are necessary to provide voltage support, stability or management of localized transmission constraints and that market solutions to provide those services do not exist.

Renewable resources

In 2008, the PUC approved a plan proposed by ERCOT to develop 18,500 MW of wind power. The PUC established five competitive renewable energy zones, or CREZ, in West Texas and the Texas Panhandle, where these resources are located, and approved a CREZ transmission plan to develop transmission capacity necessary to deliver, in a manner that is most beneficial and cost-effective to customers, renewable energy from these zones. In 2009, the PUC approved the results of a bid process, in which entities were selected to construct the transmission facilities (see the Renewable energy section).

In March 2017, Southwestern Public Service filed in Docket No. 46936 to develop two wind generation facilities, a 478-MW plant that would be located in Hale County, Texas, and a 522-MW facility, known as the Sagamore Wing Project, that would be located in Roosevelt County, New Mexico. The company sought a determination that the proposal is in the public interest, a certificate of convenience and necessity for the project, and approval of a proposal to address cost recovery between commercial operation and the date the plants are reflected in rate base and other ratemaking provisions. On April 27, 2018, the PUC tentatively adopted a settlement calling for approval of the project, as well as a purchased power contract with Bonita Wind for the output from 230 MW of wind generation. A final order was issued in May 2018.

In July 2017, Southwestern Electric Power Company filed (Docket No. 47461) for approval to acquire a 70% interest in the Wind Catcher Energy Connection Project that would be located in Texas and Oklahoma and would provide 1,900 MW of capacity. The company would acquire the facility as of its commercial operation date, which is expected to be in the third quarter of 2020. The PUC staff recommended that the commission deny the application because it is not required for reliability purposes and because the staff found the purported cost savings to be speculative. On July 26, 2018, the PUC voted to reject the proposal due to insufficient customer protections. The company has since backed out of the deal.

Battery storage

On Jan. 25, 2018, the PUC dismissed without prejudice a request by AEP Texas, in Docket No. 46368, for approval to install lithium-ion battery storage facilities at two locations, Woodson and Paint Rock, on its distribution system in lieu of expanding/upgrading traditional distribution facilities in these areas. The company sought an affirmative finding from the PUC that the batteries would be classified as distribution assets for ratemaking purposes and prudent costs would be eligible for inclusion in rate base. AEP Texas proposed to depreciate the investment over a 15-year useful life. In dismissing the case, the commissioners indicated that they wanted to address these issues on a generic basis through a rulemaking.

A similar proposal filed by Electric Transmission Texas was approved by the PUC in 2009 (Docket No. 35994). However in that case, the battery facility was classified as part of transmission rate base. Oncor Electric Delivery Co. LLC operates five 25-kW batteries installed on a load-serving transformer intended for the company to study battery performance.

The PUC opened a generic proceeding in 2018 to look at whether transmission and distribution utilities could own battery storage facilities under state law (Docket No. 48023). In the case, transmission and distribution companies argued that the law permits their ownership of battery storage. Retail electric providers and consumers argued an owner or operator of battery storage devices must register as a power generator under the state's restricting statutes. The commission paused the rulemaking, seeking guidance from the legislature. A related bill has been introduced (see the Legislation section).

In a rate case filed on April 5, 2019, CenterPoint Energy Houston Electric seeks approval to install battery storage technology to mitigate the intermittency created by distributed generation facilities connected to its grid. The company proposes to include the investment in rate base. (Section updated 4/23/19)

Renewable Energy

State law required renewable resource capacity in the state to reach 5,880 MW by 2015, with the standard phased in as follows: 2,280 MW by 2007; 3,272 MW by 2009; 4,262 MW by 2011; 5,256 MW by 2013; and 5,880 MW in 2015. 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."

In 2008, the PUC approved a plan to develop 18,500 MW of wind power. The PUC selected five competitive renewable energy zones, or CREZ, in West Texas and the Texas Panhandle region in which these resources were located and approved a plan to develop transmission capacity necessary to deliver renewable energy from the CREZ to load centers. In 2009, the PUC approved the results of a competitive bid process in which entities were selected to construct the transmission facilities. Winning bidders included: Oncor Electric Delivery Co.; Electric Transmission of Texas LLC; Lower Colorado River Authority; NextEra Inc. subsidiary Lone Star Transmission LLC; Wind Energy Transmission Texas LLC, a joint venture that includes Brookfield Asset Management; privately owned Sharyland Utilities; LS Power unit Cross Texas Transmission LLC; and other minority parties including Bandera Electric Cooperative, Brazos Power Electric Cooperative, South Texas Electric Cooperative and Texas Municipal Power Agency.

With regard to cost recovery, the established transmission and distribution utilities and cooperatives with pre-existing service territories in Texas were permitted to seek rate recognition of the new investment through their transmission cost recovery factors (see the Adjustment clauses section).

Entities that did not previously operate in Texas were designated as start-up transmission-only utilities. The PUC established initial rates for these companies through the traditional base rate case process; the PUC has approved use of the transmission cost of service mechanism for incremental investment. All of the lines are now in operation.

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Emissions Requirements

In 2015, the U.S. Environmental Protection Agency, or EPA, released the final version of its Clean Power Plan, or CPP. The CPP called for a 32% reduction nationwide in the domestic power sector's carbon dioxide emissions by 2030, versus 2005 levels.

For Texas, the CPP called for a 33% reduction. Twenty-seven states, including Texas, challenged the legality of the rule, 18 states supported the rule and five states took no legal stance. In February 2016, the U.S. Supreme Court stayed the rule, pending the outcome of a review by the U.S. Court of Appeals for the District of Columbia Circuit, or D.C. Circuit. The stay prevents the CPP from becoming effective until the D.C. Circuit issues a ruling on the merits and the Supreme Court takes action on any subsequent appeals from that ruling.

In keeping with the Trump administration's promise to rescind CPP, in October 2017 the EPA Administrator began the formal process of reversing the efforts made to date to implement the CPP.

On Aug. 21, 2018, the EPA announced the proposed Affordable Clean Energy, or ACE, rule to replace the CPP. The ACE rule would focus on greenhouse gas emissions and efficiency improvements at existing coal-fired power plants. (Section updated 4/23/19)

Reliability Issues

Various proceedings are pending in which the PUC is looking into resource adequacy issues. For additional detail, refer to the Electric regulatory reform/industry restructuring and Integrated resource planning sections. (Section updated 4/23/19)

Rate Structure

In December 2017 decisions for El Paso Electric Co., or EPE, and Southwestern Electric Power Co., or SWEPCO, as well as other rate cases decided over the last several years, the PUC has approved allocations of the authorized rate changes in a manner intended to reduce inter-class rate subsidies. In so doing, the PUC has taken a gradual approach in order to minimize rate shock. This has generally resulted in residential ratepayers experiencing a higher-than-system-average rate increase, while large-volume customers experienced a smaller-than-system-average rate increase.

In addition, in certain instances, including the above-noted December 2017 rate case for EPE, the PUC has approved proposals to increase monthly fixed customer charges so as to allow a greater portion of a utility's fixed costs to flow through these charges.

In addition, new EPE customers with an expected load greater than 400 kW will be required to take service under time-of-use, or TOU, rates but will have a one-time opportunity to opt out of the TOU alternative at the end of 12 months of service under that rate and take service thereafter under the standard service rate.

In a December 2018 rate case decision for Texas-New Mexico Power Co., the PUC adopted a settlement that provides for a greater portion of fixed costs to be recovered through fixed monthly customer charges versus volumetric rates. Residential monthly charges, comprised of a customer charge and a metering charge, are to increase to $7.85 per month from $6.25 per month, about a 26% increase. For small commercial customers the monthly customer charges are to rise to $8.36 from $4.70, about a 78% increase. The monthly charges for larger commercial and industrial customers will increase to $24.56 from $13.30, about an 85% increase. For primary customers, fixed monthly charges will rise by about 4% to $248.48 from $239.48.

Similarly, in a December 2018 rate case for Entergy Texas Inc., the PUC adopted a settlement providing for the fixed monthly customer charge to increase to $10.00 from $7.00 for residential customers and to $14.19 from $10.10 for small general-service customers.

Distributed generation/net metering

There is no statewide net metering mandate.

Distributed generation, or DG, owners must apply to the utility to interconnect to the utility system. In most cases, the customer-owner must agree to the installation of two separate meters, one to tabulate power inflows and the other for outflows. Incremental costs associated with the installation of the meters are charged to the customer, but the meter is owned by the utility.

For DG owners connected to vertically integrated utilities, the customer-owners are compensated for power produced in excess of that needed to meet the customer's demand at a price based on the utility's avoided cost.

El Paso Electric Co., or EPE, has offered net metering since 2011 for customers with eligible DG resources of 50 kW or 100% of electricity consumption, whichever is less. For DG customers within EPE's service territory, the company must install bidirectional meters with the customer's energy production to be applied to offset that customer's consumption for that billing period, essentially compensating the DG customer at the full retail rate rather than avoided cost. Excess generation beyond that is credited at avoided cost.

In a December 2017 rate case decision, the PUC adopted a settlement under which newly connected EPE DG customers will be subject to minimum monthly bill requirements.

In a case for SWEPCO that was decided in December 2017, the PUC approved a new distributed renewable generation, or DRG, tariff under which the company is to bill the customer for all electricity supplied by SWEPCO at standard retail rates and pay the customer for the electricity supplied to SWEPCO at the company's avoided cost of energy. Under the new offering, SWEPCO's avoided-energy-cost payments to the DRG customer will reflect an average monthly day-ahead Southwest Power Pool market price.

For DRG owners in areas in which customer choice has been introduced, the owner must sell the surplus electricity produced to the retail electric provider that serves the owner's load at a value agreed upon by the owner and the provider.

In 2016, the PUC approved amendments to its existing generic rules pertaining to interconnection agreements involving DG owners. The amendments are designed to allow an end-use customer to either be a party to an interconnection agreement with the incumbent utility or select any of the following types of entities to be the non-utility party to the interconnection agreement: the owner of the DG facility, an owner of rights to energy produced from the DG facility or the owner of the premises on which the DG facility is located.

Electric vehicles

In a rate case filed on April 5, 2019, CenterPoint Energy Houston Electric proposes to change its facilities extension policies to reduce the contribution in aid of construction that would otherwise apply to extend service to third-party electric vehicle plug-in stations. (Section updated 4/23/19).