Moody's
INVESTORS SERVICE

Presentation to LIPA's Board of Directors

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Agenda

1. Key Drivers for LIPA's Improved Credit Profile
2. Scoring under Moody's Methodology
3. Select Comparables

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Key Drivers for Improved Credit Profile

Key Drivers for Improving Credit Outlook

- LIPA’s credit profile has improved considerably since 2013 due in part to:
  - LIPA Reform Act (July 2013)
  - Transition to new service provider (PSEG Long Island) (January 2014)
  - 2016-2018 rate plan (January 2016)
  - Board’s adoption of Policy on Debt and Access to Credit Markets (September 2016)

Key Drivers for Improved Credit Outlook

LIPA Reform Act

» Established a rate review process for a three-year rate proposal to take effect in January 2016

» Authorized the issuance of restructuring bonds to retire higher coupon bonds

New Service Provider

» Shifted accountability to service provider and included specific operational and customer service goals

» Subsequent improvements in customer satisfaction levels have reduced political interference risk

Three-year Rate Plan

» Approved rate increases in each of 2016, 2017 and 2018

» Included automatic rate recovery mechanisms that provide protection against certain external factors

Policy on Debt and Access to Credit Markets

» Adopted financial policies devised to improve LIPA's financial position

» Include annual debt coverage targets, maintenance of minimum levels of liquidity and limits on debt issuance to fund capital spending

Key Drivers for Improved Credit Outlook

» Results: Improved financial performance and positive rating trajectory

	2012	2016	2017	2018
Fixed Obligation Charge Coverage	1.11x	1.11x	1.16x	1.27x
Debt Ratio	131%	110%	101%	99%
Days Cash on Hand	37	143	146	159
Source: Moody's Investors Service				

	2013 Rating (Outlook)	2018 Rating (Outlook)
First Lien Bonds	Baa1 (negative)	A3 (positive)
Subordinated Lien Bonds	Baa2 (negative)	Baa1 (positive)

Key Drivers for Improved Credit Outlook

- Rating outlook was revised to positive from stable in October 2018
- A rating outlook is an opinion regarding the likely rating direction over the medium term (typically 12-18 months)
- Will likely convene a rating committee within the next 12 months to resolve the positive rating outlook

Moody's Press Release dated October 2018:

The positive outlook reflects our expectation for continued improvement in operational and financial performance. A near-term challenge facing LIPA's management will be the ability to manage continued improvements outside the purview of the rate plan, which expires in 2018. While LIPA will continue to benefit from the existing suite of recovery mechanics, annual base rate increases beyond 2018 have not been predetermined. Going forward, LIPA is only required to submit a proposed rate increase for regulatory review if it would increase aggregate revenues by more than 2.5%. While we do not expect LIPA to exceed 2.5% over the near-term, such a request, if warranted, could potentially trigger political scrutiny.

FACTORS THAT COULD LEAD TO AN UPGRADE

Continued operational and financial improvements over the next 12-18 months, including satisfactory operational metrics combined with a reduction in LIPA's debt ratio below 100%, the maintenance of at least 140 days cash on hand and continued positive trend in LIPA's fixed obligation charge ratio, could increase the possibility of an upgrade.

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Scoring under Moody's Methodology

Scoring under Moody's Public Power Methodology (2016-2018 average met

Factor	Subfactor	Score	Metric
1. Cost Recovery Framework Within Service Territory		Aa	
2. Wllingness and Ability to Recover Costs with Sound Financial Metrics		A	
3. Generation and Power Procurement Risk Exposure		Aa	
4. Competitiveness		A	
5. Financial Strength and Liquidity	a) Adjusted days liquidity on hand (3-year avg) (days)	A	149
	b) Debt ratio (3-year avg) (%)	B	103%
	c) Adjusted Debt Service Coverage or Fixed Obligation Charge Coverage (3-year avg) (x)	Baa	1.18x
Preliminary Grid Indicated rating from Grid factors 1-5		**A2**	
		Notch	
6. Operational Considerations		0.0	
7. Debt Structure and Reserves		-0.5	
8. Revenue Stability and Diversity		0.0	
Grid Indicated Rating:		**A3**	

Factor 1: Cost Recovery Framework within Service Territory (25%)

» Scoring considers LIPA's monopoly position as electric utility provider and the strong socio-economic indicators of its customer base

Aaa	Aa	A	Baa	Ba	B
Monopoly with unregulated rate setting and very strong customer base and service area economy	Monopoly with unregulated rate setting and strong customer base and service area credit economy	Monopoly with unregulated rate setting; average customer base and service area economy	Regulation of rates by state; weak customer base / service area economy	Regulation of rates by state with some inconsistency; or very weak customer base or service area economy	Regulation of rates by state is unpredictable; or extremely weak customer base or service area economy

Factor 2: Willingness & Ability to Recover Costs w/ Sound Financial Metrics (25%)

» Scoring considers the availability of a strong suite of cost recovery mechanism offset by past political interference and somewhat weak financial metrics.

Aaa	Aa	A	Baa	Ba	B
Excellent rate-setting record; Rates, fuel, & purchased power cost adjustments less than 10 days; No political intervention in past or extremely high support from related government; Very limited General Fund transfers governed by policy	Strong rate-setting record; Rates, fuel, & purchased power cost adjustments 10 to 30 days; Limited political intervention in past or high support from related government; Conservative and well-defined General Fund transfers governed by policy	Adequate rate-setting record; Rates, fuel, & purchased power cost adjustments 31 to 60 days; Some political intervention in past or average support from related government; Moderate General Fund transfers	Below average rate-setting record; Rates, fuel, & purchased power cost adjustments 61 to 99 days; Persistent political intervention or below average support from related government; Large General Fund transfer not governed by policy	Some history or expectation of insufficient rate-setting; Rates, fuel, & purchased power cost adjustments 100 to 120 days; Highly political climate or very limited support from related government; Sizeable General Fund transfer not governed by policy	Lengthy record of insufficient rate-setting; Rates, fuel, & purchased power cost adjustments 120 days or more; Highly contentious political climate or clear lack of support from related government; Very sizeable General Fund transfer not governed by policy

Factor 3: Generation and Power Procurement Risk Exposure (10%)

» Considers LIPA's access to a diversified range of generating resources including natural gas, nuclear and renewables and no coal exposure

Aaa	Aa	A	Baa	Ba	B
Very limited exposure to negative repercussions from generation, procurement and commodity price risks; High degree of diversification of generation and/or fuel sources; Single generation asset typically provides less than 20% of power; or up to 20% of energy from coal-fired generation with carbon mitigation strategy	Limited exposure to negative repercussions from generation, procurement and commodity price risks; Some diversification of generation and/or fuel sources; Single generation asset typically provides less than 40% of power; or up to 40% of energy from coal-fired generation with carbon mitigation strategy	Moderate exposure to negative repercussion from generation, procurement and commodity price risks; Some reliance in one type of generation and/or fuel source, but diversified with purchased power sources; Single generation asset may provide up to 55% of power; or up to 55% of energy from coal-fired generation with carbon mitigation strategy	Moderate to high exposure to negative repercussion from generation, procurement and commodity price risks; Reliance on a single type of generation or fuel source, with somewhat limited diversification via purchased power; Single generation asset typically provides up to 75% of power; or up to 70% of energy from coal-fired generation with carbon mitigation strategy	High exposure to negative repercussion from generation, procurement and commodity price risks; Very high concentration in a single type of generation or very high reliance on a single fuel source, with limited diversification via purchased power; Single generation asset typically provides up to 75% of energy from coal-fired generation with carbon mitigation strategy, or up to 50% of energy from coal with no mitigation strategy	Very high exposure to negative repercussion from generation risks; very high concentration in a single type of generation, almost entirely reliant on a single fuel source, with very limited diversification via purchased power; Single generation asset typically provides over 85% of power; or over 85% of energy from coal-fired generation with carbon mitigation strategy, or over 50% of energy from coal-fired generation with no mitigation strategy

Factor 4: Competitiveness (10%)

» While rates are higher than state averages, they compare favorably to neighboring utilities

Aaa	Aa	A	Baa	Ba	B
Extremely competitive current and expected rates in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates more than 25% below state average); and virtually no material prospective cost pressures that could lead to higher rates	Very competitive current and expected rates in the state and/or compared to neighboring utilities on a consistent basis (e.g. average system rates in a range of 7.5% to 25% below state average); very low likelihood of material prospective cost pressures that could lead to higher rates	Competitive current and expected rates in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 7.5% below state average to 7.5% above state average); modest likelihood of material prospective cost pressures that could lead to higher rates	Somewhat competitive current and expected rates in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 7.5% to 25% above state average); high likelihood of material prospective cost pressures that could lead to higher rates	Uncompetitive current or expected rates in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 25% to 35% above state average); or high likelihood of imminent, material cost pressures that could lead to higher rates	Extremely uncompetitive current or expected rates in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates more than 35% above state average); or currently in a period of persistent cost pressures that are causing material rate increases

Factor 5: Financial Strength (30%)

All Three Year Averages:

- Sub-factor 5A – Adjusted Days Liquidity on Hand (10%)
- Sub-factor 5B – Debt Ratio (10%)
- Sub-factor 5C – Fixed Obligation Charge Coverage (10%)

Sub-factor	Aaa	Aa	A	Baa	Ba	B
Adjusted days liquidity on hand (days)	≥ 250 days	≥ 150 days to 249 days	≥ 90 days to 149 days	≥ 30 days to 89 days	≥ 15 days to 30 days	Less than 15 days
Debt ratio (%)	Less than 35%	≥ 35% less than 60%	≥ 60% less than 75%	≥ 75% less than 90%	≥ 90% less than 100%	≥ 100%
Adjusted Debt Service Coverage OR Fixed Obligation Charge Coverage (x)	≥ 2.50x	≥ 2.00x to 2.49x	≥ 1.50x to 1.99x	≥ 1.10x to 1.49x	≥ 1x to 1.1x	< 1x

Scorecard Notching

Notching considerations

- **Debt Structure and Reserves: -0.5 Notches**
  - Considers the lack of dedicated debt service reserve for LIPA's non-UDSA debt offset by the maintenance of at least 100 days of cash on hand

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Select Comparables

Select Comparables

2018 key financial metrics for a select group of large public power issuer

Obligor Name	Senior Lien Rating	Outlook	Operating Revenue ($'000)	Debt Outstanding ($'000)	Fixed Obligation Charge Coverage (x)	Debt Ratio (%)	Total Days Cash on Hand (days)
Austin (City of) TX Electric Enterprise, TX	Aa3	Stable	1,400,523	1,382,100	3.31	39.6	226
Bonneville Power Administration, WA	Aa1	Negative	3,710,300	15,032,000	1.30	86.0	89
JEA, FL	A2	Negative	1,275,255	2,150,040	1.84	58.7	172
Long Island Power Authority, NY	A3	Positive	3,857,355	9,842,789	1.27	98.7	159
Los Angeles Department of Water & Power, CA Electric Enterprise, CA	Aa2	Negative	3,804,221	9,277,415	1.63	69.4	259
Lower Colorado River Authority, TX	A2	Stable	1,035,400	3,620,100	1.50	67.1	458
Metropolitan Government of Nashville & Davidson County, TN Electric Enterprise, TN	Aa2	No Outlook	1,324,224	642,655	3.11	40.0	126
New York State Power Authority, NY	Aa1	Stable	2,689,000	2,399,000	2.52	37.1	160
Orlando Utilities Commission, FL	Aa2	Stable	902,671	1,528,860	1.73	49.1	222
Sacramento Municipal Utility District, CA	Aa3	Negative	1,595,455	2,897,180	1.80	68.8	213
Salt River Project Agricultural Improvement and Power District, AZ	Aa1	Stable	3,196,486	4,466,264	2.65	42.0	270
San Antonio (City of) TX Combined Utility Enterprise, TX	Aa1	Stable	2,620,269	5,644,975	1.82	57.9	359
Snohomish County Public Utility District 1, WA Electric Enterprise, WA	Aa3	Stable	682,269	436,190	1.95	14.0	181
South Carolina Public Service Authority, SC	A2	Negative	1,806,620	7,292,262	1.08	117.6	283

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RATING METHODOLOGY

US Public Power Electric Utilities With Generation Ownership Exposure

This rating methodology replaces "US Public Power Electric Utilities With Generation Ownership Exposure", last revised on March 1, 2016. We have updated some outdated links and removed certain issuer-specific information.

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Summary

This rating methodology explains our approach to assessing credit risk for US Public Power Electric Utilities with Generation Ownership Exposure. This document provides general guidance that helps issuers, investors, and other interested market participants understand how qualitative and quantitative risk characteristics are likely to affect rating outcomes for US public power electric utilities whose credit profile is largely influenced by power generation ownership. 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.

This report includes a detailed scorecard. The scorecard is a reference tool that can be used to approximate credit profiles within the US public power electric utilities with generation ownership exposure sector in most cases. The scorecard provides summarized guidance for the factors that are generally most important in assigning ratings to issuers in the US public power electric utility sector whose credit profile is largely influenced by power generation ownership. However, the scorecard is a summary that does not include every rating consideration. The weights shown for each factor in the scorecard represent an approximation of their importance for rating decisions but actual importance may vary substantially. The scorecard-indicated rating is not expected to match the actual rating of each issuer.

The scorecard contains five factors that are important in our assessment for ratings in the US public power electric utilities with generation ownership exposure sector:

1. Cost Recovery Framework Within Service Territory
2. Willingness and Ability to Recover Costs with Sound Financial Metrics
3. Generation and Power Procurement Risk Exposure
4. Competitiveness
5. Financial Strength and Liquidity

THIS METHODOLOGY WAS UPDATED ON JULY 27, 2018. WE HAVE REMOVED A FACTUALLY INACCURATE STATEMENT FROM PAGE 4.

The scoring for factors 1-5 is aggregated to produce a preliminary scorecard-indicated rating that is adjusted upwards or downwards based on our view of scoring for factors 6, 7 and 8. Scoring for factors 6-8 can result in upward or downward notching for issuers that exhibit better or worse than typical positions in these areas.

6. Operational Considerations
7. Debt Structure and Reserves
8. Revenue Stability and Diversity

The combination of factors 1-8 results in the scorecard-indicated rating. An issuer's scoring on a particular scorecard factor or sub-factor often will not match its overall rating.

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, 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 an issuer-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a scorecard format. The scorecard used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex scorecard that would map scorecard-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 description of factors that drive rating quality

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

The Appendix provides the full scorecard.

Due to the prevalence in this sector of financing secured by a senior net revenue pledge (senior revenue bonds), the scorecard in this methodology is calibrated for this rating class, and the rating utilized for comparison to the scorecard-indicated rating is the issuer's senior revenue bond rating. Ratings for individual debt instruments also factor in assessments reflected in notching for seniority level and collateral. The document that provides broad guidance for such notching decisions is our methodology for aligning corporate instrument ratings based on differences in security and priority of claim.[1] All issuers in this sector are owned by government entities in the US, and the scorecard is calibrated to incorporate the benefits of government ownership. As a result, uplift under our rating methodology for Government-Related Issuers does not apply to this sector.[2]

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

1 Access our methodology for notching corporate instrument ratings based on differences in security and priority of claim by using the link in the Related Research section of this report.

2 Our methodology for rating Government-Related Issuers (GRIs) can be accessed using the link in the Related Research section of this report.

securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities.[3]

About the Rated Universe

This methodology is applicable to US public power utilities that own significant generation assets or that obtain at least 20% of their capacity/energy from directly owned power generation assets and/or from participation in municipal joint action agencies (JAAs). The issuers rated under this methodology include autonomous US federal, state and local power authorities, and departments of a municipality. The bonds issued by all of these entities are serviced solely from their utility and related operations; they do not represent general obligations of the governments that own or control them. Some of the utilities rated under this methodology are integrated, combining generation with high voltage transmission and lower-voltage distribution systems to sell power directly to end-users. Some issuers rated hereunder do not have distribution systems – they sell the power they generate and/or procure on a wholesale basis to other utilities.

Further characteristics that typify US public power utilities with generation exposure include:

» Near monopoly position in providing an essential service

» Unregulated and independent local rate-setting authority[4]

» Cost structure that is generally lower than investor-owned utilities due to the ability to issue lower cost tax-exempt debt and, for some, the availability under federal statute of federal low cost preference power

» Although not typically subject to income taxes or property taxes, most make payments in lieu of taxes (PILOTs); some also may make payments referred to as General Fund Transfers (GFTs)

» Lack of profit motive or need to generate a return on equity

US public power utilities with generation exposure under the 20% threshold on a sustained basis and those that have only transmission and distribution operations are rated under our US Municipal Utility Revenue Debt methodology.[5] Municipal joint action agencies are entities formed by a group of US municipal utilities (participants) to provide reliable and competitively priced energy or energy related services – typically power, though they may also provide natural gas, electric transmission, or telecommunications services for energy assets. The participating municipal utility systems share an obligation established through a long-term contractual arrangement to cover the JAA's operating, capital, and debt service costs. JAAs are rated under our US Municipal Joint Action Agencies methodology.[6]

Public power electric utilities that either own significant generation assets or obtain at least 20% of their electricity from directly owned power generation assets and/or from JAA participation generally have more fundamental credit risks than other essential purpose enterprises such as public power electric utilities that do not own generation assets. These fundamental risks include exposure to commodity markets, environmental regulation and larger capital requirements to maintain, refurbish or replace generation assets.

The history of US public power utilities with generation exposure generally reflects the essentiality of their service, monopoly positions, and, in most cases, autonomous rate-setting ability. However, US public

[3] The methodologies covering our approach to these cross-sector considerations can be found in the Related Research section of this report.

[4] Certain exceptions may apply.

[5] Our methodology for rating US municipal utility revenue bonds can be accessed using the link in the related research section of this report.

[6] Access our methodology for rating revenue bonds of US municipal Joint Action Agencies (JAA) by using the link in the related research section of this report.

power electric utilities that own generation typically have a higher degree of business complexity and credit risk than other essential municipal services such as electric and gas distribution, water, sewer, and storm water systems. Specifically, generation-owning electric utilities typically have greater operating and capital deployment risks, because they have a more complex asset conversion cycle and are subject to ongoing changes in regulations and commodity price that can affect the relative cost-efficiency of their generating fleets. While there remain many similarities with other essential purpose revenue bonds such as governance, bondholder security provisions and rate-setting flexibility, the challenging operating environment for a generation-owning electric utility is more pronounced. While there are some nuanced differences between direct ownership and JAA participation, in broad terms, a public power electric utility shares in the risks associated with JAA generation, and the scorecard factors are generally the same for these two sub-groups.

JAA participation typically takes one of two forms - a take-or-pay contract or an all requirements take-and-pay contract. Under a typical take-or-pay contract for a particular power plant, the utility is required to pay its share (usually a fixed percentage) of the JAA's total life-cycle costs of owning and operating that plant, even if the plant is not operable and regardless of whether the utility takes the power the plant generates. Termination provisions under take-or-pay contracts are essentially non-existent. Under a typical all requirements take-and-pay contract, the utility agrees to purchase all of its power needs (or a portion thereof) from the JAA and is responsible for a percentage of the JAA's total costs while the contract is in effect. The utility typically has the right to terminate the all requirements take-and-pay contract after a multi-year notice period, and the utility's obligation with respect to the JAA's costs is based on the utility's percentage share of the total power taken by all participants, which can vary over time according to usage patterns or the entry/exit of JAA participants.

Broad industry changes continue to introduce uncertainty to the public power sector, such as deregulation initiatives that have introduced a degree of competition, ongoing environmental policy changes, and supply and demand factors. Electric generation is capital intensive, and US public power electric utilities with generation exposure must make decisions that result in long-term obligations amidst a changing operating environment.

About this Rating Methodology

This report explains the rating methodology for US public power electric utilities with generation ownership exposure in several sections, which are summarized as follows:

1. Identification and Discussion of the Scorecard Factors

The scorecard in this rating methodology focuses on eight rating factors. One of these factors is comprised of sub-factors that provide further detail. Factors 6-8 are used to make notching adjustments for operational considerations, debt structure and reserves, and revenue stability and diversity.

EXHIBIT 1

US Public Power Electric Utilities with Generation Ownership Exposure Methodology Factor Scorecard

Scorecard Factors	Factor Weighting	Sub-Factors	Sub-Factor Weighting
Cost Recovery Framework Within Service Territory	25%		25%
Willingness and Ability to Recover Costs with Sound Financial Metrics	25%		25%
Generation and Power Procurement Risk Exposure	10%		10%
Competitiveness	10%		10%
Financial Strength and Liquidity	30%	Adjusted days liquidity on hand (3-year avg) (days)	10%
		Debt ratio (3-year avg) (%)	10%
		Adjusted Debt Service Coverage OR Fixed Obligation Charge Coverage (3-years avg) (x)	10%
Total	**100%**	**Total**	**100%**
Operational Considerations	(notching adjustment)		
Debt Structure and Reserves	(notching adjustment)		
Revenue Stability and Diversity	(notching adjustment)		

2. Measurement or Estimation of Factors in the Scorecard

We explain our general approach for scoring each scorecard factor or sub-factor and show the weights used in the scorecard. We also provide a rationale for why each of these scorecard components is meaningful as a credit indicator. The information used in assessing the factors and sub-factors is generally found in or calculated from information in utility financial statements, derived from other observations or estimated by our analysts.

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 an issuer'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) to illustrate the application of the scorecard. However, the factors and sub-factors in the scorecard 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 one year, several years or more.

The quantitative credit metrics in the scorecard incorporate any Moody's adjustments to the income statement, cash flow statement and balance sheet amounts.

3. Mapping Scorecard Factors to the Rating Categories

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

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

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

5. Determining the Overall Scorecard-Indicated Rating

To determine the preliminary scorecard-indicated rating before notching considerations, we convert each of the factor and sub-factor scores into a numerical value based upon the scale below.

Sub-factor score to numeric value

Aaa	Aa	A	Baa	Ba	B
1	3	6	9	12	15

The numerical score for each scorecard factor or sub-factor is multiplied by the weight for that 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.

Scorecard-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	x < 1.5
Aa1	1.5 ≤ x < 2.5
Aa2	2.5 ≤ x < 3.5
Aa3	3.5 ≤ x < 4.5
A1	4.5 ≤ x < 5.5
A2	5.5 ≤ x < 6.5
A3	6.5 ≤ x < 7.5
Baa1	7.5 ≤ x < 8.5
Baa2	8.5 ≤ x < 9.5
Baa3	9.5 ≤ x < 10.5
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 preliminary scorecard-indicated rating

Finally, we consider whether the preliminary scorecard-indicated rating score that results from factors 1-5 should be notched upward or downward based on operational considerations, debt structure and reserves, and revenue stability and diversity, in order to arrive at a final scorecard-indicated rating.

6. Appendix

The Appendix provides the full scorecard.

Factor 1: Cost Recovery Framework Within Service Territory (25% Weight)

Why It Matters

The ability to recover prudently-incurred costs in a timely manner is one of the most important credit considerations for US public power electric utilities with generation ownership exposure, as a delay in cost recovery may cause financial stress. Therefore, the monopoly status, rate autonomy and where applicable, predictability and supportiveness of the regulatory framework in which a public power utility operates – as well as the legal and political framework that underpins it - are key credit considerations that differentiate this sector from most corporate sectors. In addition, the strength and diversity of the service territory is important because it can indirectly influence a public power electric utility's cost recovery framework. Larger, more diverse service areas with greater economic wealth are better able than smaller, less diverse areas to support rate increases that may be required as a result of changes in fuel and operating costs, required capital expenditures, or other causes.

In general, the US public power electric utilities with generation ownership exposure rated under this methodology are effectively monopoly providers of essential electric services, which limits competitive threats. With few exceptions, they are not subject to rate regulation, i.e. their revenues are not subject to price controls under the jurisdiction of any state public utility service commission as part of the process to reset them periodically. Price-setting mechanisms are generally structured by management, governing boards and or city councils at their sole discretion to limit volatility wherever possible and therefore tend to be highly predictable. The benefits of monopoly status and rate autonomy are further bolstered for most public utilities by minimum bond security covenants that require current revenues to match current expenses, including payment of debt service. There are some instances where regulation of rates by state public utility service commissions does apply. In these instances, the regulators may also have an effect on capital spending decisions and efficiency targets to reduce operating costs, which can affect the public utility's business position.

How We Assess the Cost Recovery Framework Within Service Territory for the Scorecard

Collectively three components, [1] the strength of monopoly control over a service area, [2] unregulated rate raising ability, and [3] the strength of a public power utility's customer base and service area economy are core characteristics in assessing this factor. In the US, public power electric utilities have maintained a near monopoly role in their service area, limiting competitive threats to their customer base. This monopoly control, in combination with an unregulated rate setting process, provides a greater certainty of the utility's ability to access its revenue requirement from the region served. Among utilities with strong monopolies and autonomous rate-setting, assessment of the customer base and service area economic strength provides differentiation for this factor.

When evaluating the credit characteristics of the utility's service area, we consider population, employment trends, wealth indicators, and local economic diversity and growth projections. For example, we often utilize Moody's Economy.com for an assessment of current and projected economic strength of a particular service area. Weak economic characteristics and limited economic diversity would contribute to a lower score for Factor 1.

We also evaluate the wealth indicators of the population that a utility serves to gauge the ability of customers to pay their electric bills, both currently and in the future, if rates rise. Affluent residential customers generally have a higher tolerance for higher overall rates, since the electric bill is a small part of their disposable income.

We look at the relative mix of residential, commercial and industrial customers when assessing the stability of the customer base. Factor scoring for US public power electric utilities that serve a primarily residential customer base (e.g., more than 50% residential sales) would generally be favorably influenced because of benefits from the more stable load and revenue trends that typify the customer class. Alternatively, a customer base dominated by industrial load, particularly if concentrated in one or just a few industrial customers, would exert negative influence on scoring because public utilities with such a characteristic are more susceptible to economic cycles and demand changes that could affect revenue stability.

US public power electric utilities with generation ownership exposure that are subject to rate regulation typically receive lower scores for Factor 1, because rate regulation can sometimes limit or delay cost recovery. Public power electric utilities predominantly have amortizing debt and a debt service coverage requirement, so regulatory lag or cost disallowance that creates uncertainty could increase default risk. For utilities with regulated rate-setting, the regulatory framework can vary by state and may provide greater or lesser predictability in the certainty and timing of cost recovery depending on its details and the manner in which it is applied by regulators. Some states like Wisconsin and Indiana regulate public power electric utilities, but the regulation tends to be credit supportive, and regulators are required to consider bond covenants in their rulemaking. As reflected in the scorecard, regardless of other considerations in this factor, including service area economic strength and customer concentration, if a public power electric utility falls under typical state regulation (as normally applied to investor owned utilities) our assessment of Factor 1 would typically not exceed a Baa score.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Cost Recovery Framework Within Service Territory	25%	Monopoly with unregulated rate setting and very strong customer base and service area economy	Monopoly with unregulated rate setting and strong customer base and service area credit economy	Monopoly with unregulated rate setting; average customer base and service area economy	Regulation of rates by state; weak customer base / service area economy	Regulation of rates by state with some inconsistency; or very weak customer base or service area economy	Regulation of rates by state is unpredictable; or extremely weak customer base or service area economy

Factor 2: Willingness and Ability to Recover Costs with Sound Financial Metrics (25% Weight)

Why It Matters

Willingness to use the independent and local rate-setting authority guided by sound bond covenants and governance is an extremely important consideration and a heavily weighted rating factor. Unregulated public power utilities may have the ability to raise rates but there can be meaningful differences in their willingness to do so, for a variety of public policy reasons that may have the effect of placing rate-payer concerns ahead of sound financial policy. Regulated public power utilities must have both the willingness to seek rate increases and the ability to obtain the necessary regulatory approvals. In either case, implementing rate increases in a timely fashion in order to maintain sound financial credit strength has been a fundamental credit strength for most issuers in the sector. Credit risk increases in the absence of the stability and certainty that maintenance of a financial buffer provides in mitigating the impact of modest credit stress events. Political risk or (when applicable) lack of regulatory support can result in an unwillingness or inability to establish sufficient rates to maintain sound financial metrics. Without sound rate-setting that is predictable and timely, debt service coverage ratios or liquidity are likely to be compromised. This factor may be a leading indicator of the direction of future financial performance for a US public power electric utility with generation ownership exposure.

Another important aspect is the degree of support, or lack thereof, from a related governmental entity, since most public power electric utilities are owned by local governments. This matters because a city may use its broader governance authority and or financial resources to prevent financial deterioration of the utility, which serves to protect revenue bond holders. Conversely, the government owner can take distributions from the utility, typically in the form of General Fund Transfer (GFTs), that limit the latter's financial flexibility, and the government can pressure the utility to hold down rates or increase capital expenditures in a manner that is detrimental to the maintenance of sound financial metrics.

The ability to automatically adjust rates for changes in fuel or power purchase costs has become a more notable credit factor in the past decade given wide fluctuations in natural gas prices, ongoing hydrology risk, and the volatility of the wholesale power market. Some utilities source a portion of their energy needs in the wholesale market, while others have used profits from wholesale sales to reduce the revenue requirement from retail users.

Rate-setting is a dynamic process that will continue to be tested in the next several years as power supply costs rise due to increased environmental regulation, demand growth remains slow due to the slow economic recovery, and utilities shift to cleaner but sometimes more expensive sources of supply (i.e., to comply with renewable portfolio standards). A forward view of a utility's ability and willingness to set rates to recover all costs has high importance.

How We Assess Willingness and Ability to Recover Costs with Sound Financial Metrics for the Scorecard

In assessing this factor, we evaluate the governing board's rate-setting process for its transparency, timeliness and supportiveness in setting the rates and charges necessary to ensure that costs, including debt service, are fully recovered. This may include considerations regarding the utility's ability to generate targeted revenue based on underlying volume assumptions. Rate mechanisms that mitigate the impact of revenue volatility are viewed positively.

Another key part of our assessment for this factor is length of time it takes to implement new rates and collect the additional revenues. A demonstrated record of ability and willingness to change rates on a timely or pro-active basis as required to recover operating and capital costs, to provide a cushion for debt service coverage, and to maintain sound liquidity are credit positives and would likely lead to scores at the mid-to-higher end of the rating scale for this factor, when that record is expected to continue. In those cases where utilities waiver and delay on actions to adjust rates as necessary to provide timely assurance of cost recovery, we would likely score them lower for this factor than we would for those who are more proactive in adjusting their rates.

Utilities that have an automatic fuel and purchased power cost adjustment mechanism are able to recover these costs on a more timely basis. Such adjustment mechanisms would typically contribute to a higher score for this factor because the mechanisms serve to narrow the potential drain on liquidity and the resulting impact on credit quality and are of particular importance should there be a fuel price spike or a forced outage of a generating unit. A material lag before the utility can recover these costs would likely contribute to a lower score.

When assessing this factor we also consider the relationship of the local government with the electric utility. This will not always be a material consideration, as some utilities have no fiscal relationship with a local government, or the utility may have been established as a separate and independent authority. We consider who governs the utility, who sets its rates, and who issues the revenue bonds for the utility, as well as the degree to which the general government is responsible for supporting the utility in times of financial stress. Higher scores for this factor would be likely under circumstances where the interests of the utility and the government are aligned, and where a highly-rated local government has a strong record of supporting their public power electric utility in times of fiscal stress. Political risks and/or regulatory barriers that impede a utility's willingness to enact rates and charges on a timely basis that are sufficient to maintain the associated financial metrics for a utility's rating category would likely result in a lower score for this factor.

Finally, we focus on GFT policies when assessing this factor because the policies are an example of the relationship between a utility and their local government. The GFT is the transfer of surplus utility revenues from the utility to the city's General Fund. Policy-driven GFTs in very limited or conservative amounts typically contribute to higher scores for this factor, while ad hoc, larger amounts of GFTs not governed by policy typically contribute to a lower score. Established, prudent GFT policies that are accepted by both the utility and the local government add credit strength because they increase the predictability of the amount to be transferred. Alternatively, a policy established after a contentious debate for a transfer amount that represents a substantial portion of the utility's own revenues could have a negative impact, (i.e. if it produces uncompetitive electric rates or leaves limited internal funds available for utility operations, maintenance, and repairs) and contribute to a lower score for this factor.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Willingness and Ability to Recover Costs with Sound Financial Metrics	25%	Excellent rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments less than 10 days; No political intervention in past or extremely high support from related government; Very limited General Fund transfers governed by policy	Strong rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments 10 to 30 days; Limited political intervention in past or high support from related government; Conservative and well-defined General Fund transfers governed by policy	Adequate rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments 31 to 60 days; Some political intervention in past or average support from related government; Moderate General Fund transfers	Below average rate-setting record; Rates, fuel, & purchased power cost adjustments 61 to 99 days; Persistent political intervention or below average support from related government; Large General Fund transfer not governed by policy	Some history or expectation of insufficient rate-setting; Rates, fuel, & purchased power cost adjustments 100 to 120 days; Highly political climate or very limited support from related government; Sizeable General Fund transfer not governed by policy	Lengthy record of, or expectation for a prolonged period of insufficient rate-setting ; Rates, fuel, & purchased power cost adjustments 120 days or more; Highly contentious political climate or clear lack of support from related government; Very sizeable General Fund transfer not governed by policy

Factor 3: Generation and Power Procurement Risk Exposure (10% Weight)

Why It Matters

Generation and power procurement risks, power supply costs and system reliability have an important influence on a utility's ability to meet its service obligations, the competiveness of current and future rates, and financial metrics over time. Efficiently meeting its current electricity demand and planning effectively for future demand has direct bearing on a utility's leverage, customer satisfaction, rate levels, service reliability, and often on the political support for the utility. Political and regulatory support rooted in customer satisfaction can translate into a greater willingness and ability to establish the rate levels needed to keep the utility in sound financial condition.

Successful resource planning, most often accomplished through fuel source diversity and the maintenance of a sufficient but not excessive reserve margin, is fundamental to the utility's future health given the objective to provide low-cost, safe and reliable power supply to its customers. The continuing challenge of managing environmental regulations related to clean air and renewable standards underscores the importance of this factor. These standards, which can vary by state, have been increasing over time and are often litigated. This typically delays implementation, and may cloud the visibility into the standards that will eventually be enforced.

How We Assess Generation and Power Procurement Risk Exposure for the Scorecard

When assessing generation and power procurement risks, we consider the mix and diversity of a utility's power supply, as well as the cost and reliability. Maintaining a diverse fuel and resource mix increases the utility's flexibility to manage peak demand while limiting the utility's exposure to volatile commodity and energy market prices, disruptions in the delivery of a single fuel source, or increased costs associated with a particular asset, for instance the cost of environmental compliance for a coal plant. Our review of the utility's generation performance record may include indicators such as availability (% of time a generation unit is operational); capacity factor (% of capacity the generation fleet runs); and heat rates (efficiency of a generator to convert fuel into electrical energy). Additional considerations may include the primary terms and conditions of any purchase power agreements in the context of the utility's overall power supply mix, the positioning of the assets on the regional dispatch curve and the associated impact on the all-in cost of power supply, and the main drivers of the overall retail price charged to the end-use customer. Above-market power supply costs could lead to higher retail charges to end-use customers, which would likely contribute to a lower score for this factor.

We consider the utility's main generation sources, whether owned or purchased under contract, since each type (e.g. natural gas, coal, nuclear, hydro) has risks which must be properly managed. Such risks include fuel price (for instance, natural gas prices can demonstrate high seasonal volatility), transportation issues (e.g., availability of rail and barging delivery for coal, availability of peak period pipeline capacity for natural gas), safety regulations (e.g., Nuclear Regulatory Commission (NRC) regulations for nuclear generation facilities), hydrology risks for hydroelectric generating units, and environmental compliance issues for coal-fired generating units.

In evaluating the generation strategy, we consider the utility's flexibility with regard to fuel-switching. Alternate transportation modes/routes and fuel storage may also be meaningful considerations. By maintaining sufficient power resource reserve margin, a utility is better positioned to manage an unexpected forced outage of a large generating facility. Risk exposures that are not adequately mitigated would contribute to a lower score on this factor.

Public power electric utilities with limited diversification or that are heavily reliant on a single type of generation and fuel source typically score lower on this factor. In some cases, such as high reliance on hydro, the risk may be mitigated somewhat by the cost competitiveness of the fuel source, provided there is ready access to alternative sources of generation. Utilities with a high reliance on coal-fired generation are likely to score lower on this factor due to their vulnerability to future EPA regulations, including under the Clean Power Plan.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Generation and Power Procurement Risk Exposure[7]	10%	Very limited exposure to negative repercussions from generation, procurement and commodity price risks; High degree of diversification of generation and/or fuel sources; Single generation asset typically provides less than 20% of power; or up to 20% of energy from coal-fired generation with carbon mitigation strategy	Limited exposure to negative repercussions from generation, procurement and commodity price risks; Some diversification of generation and/or fuel sources; Single generation asset typically provides less than 40% of power; or up to 40% of energy from coal-fired generation with carbon mitigation strategy	Moderate exposure to negative repercussion from generation, procurement and commodity price risks; Some reliance in one type of generation and/or fuel source, but diversified with purchased power sources; Single generation asset may provide up to 55% of power; or up to 55% of energy from coal-fired generation with carbon mitigation strategy	Moderate to high exposure to negative repercussion from generation, procurement and commodity price risks; Reliance on a single type of generation or fuel source, with somewhat limited diversification via purchased power; Single generation asset typically provides up to 75% of power; or up to 70% of energy from coal-fired generation with carbon mitigation strategy	High exposure to negative repercussion from generation, procurement and commodity price risks; Very high concentration in a single type of generation or very high reliance on a single fuel source, with limited diversification via purchased power; Single generation asset typically provides up to 75% of energy from coal-fired generation with carbon mitigation strategy, or up to 50% of energy from coal with no mitigation strategy	Very high exposure to negative repercussion from generation, procurement and commodity price risks; very high concentration in a single type of generation, almost entirely reliant on a single fuel source, with very limited diversification via purchased power; Single generation asset typically provides over 85% of power; or over 85% of energy from coal-fired generation with carbon mitigation strategy, or over 50% of energy from coal-fired generation with no mitigation strategy

Factor 4: Competitiveness (10% Weight)

Why It Matters

Despite the closed retail market for almost all public power electric utilities, an important advantage of the sector is the price competitiveness for retail and/or wholesale customers, especially relative to investor-owned utilities. We would expect increased political and regulatory risks if the utility has uncompetitive rates, leading to a potentially more challenging rate setting environment despite the rate autonomy that is prevalent in the sector. High retail rates cause pressure on the governing board (and regulators when applicable) to delay rate increases or perhaps even lower rates, which could affect the utility's ability to recover costs and weaken debt service coverage. In addition, high rates may discourage economic development and contribute to a stagnant or declining revenue base, which could impact debt service coverage in the long-run. Public power electric utilities with large, energy-intensive customers that contribute significantly to their net income could face pressure if high industrial or commercial retail rates motivate those large customers to relocate. The shuttering/relocation of large users can weigh negatively on the local economy and also place additional upward pressure on electric rates for the utility's remaining customers.

How We Assess Competitiveness for the Scorecard

In assessing this factor, we consider a utility's average system retail rate in the context of its regional peers. In many cases, the state average rate is very relevant, but a competiveness comparison to neighboring utilities may be more important for some issuers. For instance, in some states a single utility may dominate, rendering in-state comparisons less meaningful. For public utilities near major metropolitan areas, the

7 In scoring this factor, generation includes generation from owned assets and via participation in JAAs, unit power agreements and similar arrangements.

important comparison may be to neighboring utilities, especially if there are transmission constraints to in-state utilities that may have a different cost base.

A comparison of retail rates is generally considered in terms of the system average revenue per kilowatt hour (cents/kwh). The average system rate is a useful benchmark that can allow comparisons among regional markets, but it does not distinguish between different customer classes and rate designs. For instance, for some utilities with heavy industrial loads, competitiveness of the industrial rate may be more important than the system average rate, especially if industry is a major driver of employment. For utilities in a contentious political/regulatory environment, residential rates may be most important. For utilities with meaningful wholesale generation, we typically also compare wholesale rates against regional benchmarks to assess the competitive position of that portion of the utility's business, which can be a meaningful consideration, because in most cases the wholesale business is less stable than regulated retail supply.

Our view in this factor is forward-looking, and when relevant we consider future capital spending plans and other cost pressures, such as those for environmental compliance, to assess the likelihood they will create a need for rate increases that pressure the utility's competitive standing.

Generally, those utilities with a stronger competitive starting point compared to the relevant benchmark and that are not facing material cost pressures have more flexibility to withstand competitive challenges and score toward the higher end of the scorecard for this factor. Competitively challenged utilities, whether on a current basis or prospectively would typically score in the mid-to-lower portion of the scorecard for this factor.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Competitiveness	10%	Extremely competitive current and expected rates[8] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates more than 25% below state average); and virtually no material prospective cost pressures that could lead to higher rates	Very competitive current and expected rates[8] in the state and/or compared to neighboring utilities on a consistent basis (e.g. average system rates in a range of 7.5% to 25% below state average); very low likelihood of material prospective cost pressures that could lead to higher rates	Competitive current and expected rates[8] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 7.5% below state average to 7.5% above state average); modest likelihood of material prospective cost pressures that could lead to higher rates	Somewhat competitive current and expected rates[8] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 7.5% to 25% above state average); high likelihood of material prospective cost pressures that could lead to higher rates	Uncompetitive current or expected rates[8] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 25% to 35% above state average); or high likelihood of imminent, material cost pressures that could lead to higher rates	Extremely uncompetitive current or expected rates[8] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates more than 35% above state average); or currently in a period of persistent cost pressures that are causing material rate increases

[8] Retail rates are typically calculated as average revenue per kilowatt hour sold; however, this factor may also be assessed based on competitive positioning of rates in a dominant customer class (residential, commercial, industrial or wholesale).

Factor 5: Financial Strength and Liquidity (30% Weight)

Why it Matters

A utility's ultimate credit profile must incorporate its financial metrics, as any public power utility that is substantially weaker than its peers in terms of liquidity, cash flow generated in relation to debt service, or debt relative to the value of its asset base will generally have a higher probability of default. Public power electric utilities, especially those that own generation, are typically capital intensive with an ongoing need to invest in their assets and have a higher leverage profile than their investor-owned counterparts, which typically necessitates consistent access to debt capital markets to assure adequate sources of funding. A utility's financial strength is key to its maintaining this market access and, in general, its long-term viability. Public power electric utilities with weaker metrics may find that their access to markets decreases rapidly when markets shift or their debt load is viewed as unsustainable.

When examining financial strength, there is no single measure that can predict the likelihood of default. We utilize metrics that are indicators for liquidity resources in relation to operating and maintenance expenses, the capacity of the issuer to service its debt and the size of its debt burden relative to its assets. Comparison to peers is typically useful.

How We Assess Financial Strength and Liquidity for the Scorecard

Adjusted Days Liquidity on Hand Ratio (10% weight)

The formula for Adjusted Days Liquidity on Hand Ratio (days) is as follows:

(Available unrestricted cash and investments + Eligible unused bank lines and capacity under commercial paper programs) x 365 days / (Utility's annual operating and maintenance expenses exclusive of depreciation and amortization expenses and the debt portion of annual payments made to JAAs under take-or-pay contracts)

For the numerator, certain designated reserves (but excluding debt service funds and reserve requirement) that are available when needed by the utility are included in unrestricted cash and investments. The unused portion of eligible bank lines (described below) are included. Capacity under commercial paper programs is included without duplication to unused eligible bank lines. Some utilities have commercial paper programs that are backed by letters of credit, and the unused portion is included when the LC issuing bank is rated P-1.

To be included in this ratio, eligible bank lines must meet all of the following criteria:

- » Committed facilities
- » Remaining tenor of committed drawdown availability is at least one year
- » Absence of impediments to drawdown, including:
  - – No material adverse change (MAC) representation requirement for borrowings
  - – No material adverse litigation (MAL) representation requirement for borrowings
  - – No covenants set at a level reasonably expected to restrict borrowings
- » If bilateral, provided by a bank rated P-1
- » If syndicated, provided by a group of banks predominantly rated P-1

Bank lines that do not meet the eligibility requirements are not included in calculating the ratio. However, depending on their strength, they may be assessed qualitatively as a credit positive if they constitute incremental liquidity as part of prudent financial policies. While bank lines over a year are included in the ratio, bank line maturities are considered in the broader context of a utility's future cash flow requirements, including capital expenditures, and loan/bond amortizations. Longer dated tenors are more favorable from a credit perspective.

Debt Ratio (10% weight):

(Gross debt – Debt service funds – Interest payable and debt service reserve funds) / (Gross fixed plant assets –Accumulated depreciation on plant + Net working capital)

Net working capital is defined as cash and investments plus receivables expected to be collected minus current liabilities unrelated to debt.

Adjusted Debt Service or Fixed Obligation Charge Coverage Ratio (10% weight)

In order to improve comparability between utilities that have chosen different generation procurement and financing strategies, there are some differences between their coverage ratios. For a public power electric utility that does not have any generation exposure via take-or-pay contracts with JAAs, we use the Adjusted Debt Service Coverage Ratio. For a utility that purchases some portion of its power under a take-or-pay contract with a JAA that has issued debt related to fulfilling that contract, we use the Fixed Obligation Charge Coverage Ratio.

Adjusted Debt Service Coverage Ratio:

(Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFTs) / Aggregate annual debt service

In the numerator, recurring revenue and recurring expenses exclude special, one-time items. Annual cash operating expenses exclude depreciation and amortization expenses. GFTs are general fund transfers.

Most public power utilities transfer a portion of their surplus revenues to a municipal government at an agreed upon level. While the transfers typically come after debt service in the legal flow of funds, in practical terms the transfer is a requirement that in many cases is made on a monthly basis. Therefore, our Adjusted Debt Service Coverage Ratio treats the transfer as akin to an operating expense, which differentiates it from the traditional bond ordinance debt service coverage ratio. We utilize the adjusted debt service coverage ratio in the scorecard because it provides a better overall indicator of a utility's operating results that provides greater comparability among public power electric utilities. In some cases, the bond ordinance coverage ratio may also be important to our analysis.

Fixed Obligation Charge Coverage Ratio:

(Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFT + Debt service portion of annual payments made to JAAs under take-or-pay contracts) / (Aggregate annual debt service + Debt service portion of annual payments made to JAAs under take-or-pay contracts)

In the numerator, recurring revenue and recurring expenses exclude special, one-time items. Annual cash operating expenses exclude depreciation and amortization expenses. GFTs are general fund transfers.

Many public power enterprises finance the development or purchase of generation assets through JAAs under take-or-pay contracts to increase power reliability, diversify the power resource mix, and lower power costs. We view a take-or-pay contractual obligation as fixed and the debt service portion of annual payments made to the JAA as a debt service obligation of the utility.

Financial Strength and Liquidity	Weight	Aaa	Aa	A	Baa	Ba	B
Adjusted days liquidity on hand[9] (3-year avg) (days)	10%	≥ 250	150 - 250	90 - 150	30 - 90	15 - 30	< 15
Debt ratio (3-year avg)[10] (%)	10%	< 35%	35% - 60%	60% - 75%	75% - 90%	90% - 100%	≥ 100%
Adjusted Debt Service Coverage[11] OR Fixed Obligation Charge Coverage[12] (3-years avg) (x)	10%	≥ 2.5x	2x - 2.5x	1.5x - 2x	1.1x - 1.5x	1x - 1.1x	< 1x

Factors 6, 7, and 8

These factors result in upward or downward adjustments to the preliminary scorecard-indicated rating resulting from factors 1-5. In aggregate, these factors can result in a total of 3 notches up or down from the preliminary scorecard-indicated rating to arrive at the scorecard-indicated rating. In the unusual circumstance that the importance of these factors in assessing the issuer's credit profile is greater than can be incorporated within the range of this notching band, they may nonetheless be incorporated in the actual rating – please see Other Rating Considerations.

Factor 6: Operational Considerations

Operational considerations include construction risks and whether the utility is a vital service provider. In aggregate, operational considerations can result in adjustments ranging from 2 notches down to one notch up.

We assess each utility's construction risks and may apply up to 2 negative notches to the preliminary scorecard-indicated rating in accordance with the construction program's complexity, technical difficulty, scale relative to the size of the utility, and risk-allocation between the utility and its contractors for cost over-runs and delays, including liquidated damages. We may consider feasibility studies and other reports provided by third-party consulting engineers to inform our assessment of the risks associated with a particular project. Risk mitigation may include fixed-price contracts with liquidated damages, performance

9 Defined as: (Available unrestricted cash and investments + Eligible unused bank lines and capacity under commercial paper programs) x 365 days / (Utility's annual operating and maintenance expenses exclusive of depreciation and amortization expenses and the debt service portion of annual payments made to JAAs under take-or-pay contracts). For the numerator, certain designated reserves (but excluding debt service funds and reserve requirement) that are available when needed by the utility are included in unrestricted cash and investments. The unused portion of eligible bank lines are included. Capacity under commercial paper programs is included without duplication to unused eligible bank lines. To be included in this ratio, eligible bank lines must meet all of the following criteria:

- Committed facilities
- Remaining tenor of committed drawdown availability is at least one year
- Absence of impediments to drawdown, including:
  - No material adverse change (MAC) representation requirement for borrowings
  - No material adverse litigation (MAL) representation requirement for borrowings
  - No covenants set at a level reasonably expected to restrict borrowings
- If bilateral, provided by a bank rated P-1
- If syndicated, provided by a group of banks predominantly rated P-1

10 Defined as: (Gross debt – Debt service funds – Interest payable and debt service reserve funds) / (Gross fixed plant assets –Accumulated depreciation on plant + Net working capital). Net working capital is defined as cash and investments plus receivables expected to be collected minus current liabilities unrelated to debt.

11 Defined as: (Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFTs) / Aggregate annual debt service. In the numerator, recurring revenue and recurring expenses exclude special, one-time items. Annual cash operating expenses exclude depreciation and amortization expenses. GFTs are general fund transfers.

12 Defined as: (Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFT + Debt service portion of annual payments made to JAAs under take-or-pay contracts) / (Aggregate annual debt service + Debt service portion of annual payments made to JAAs under take-or-pay contracts).

and payment bonds, and program management oversight. Technological risk is heightened for first-in-kind engineering risks.

We assess whether the utility provides vital services to a very large economic region and may apply up to one positive notch, for instances where the utility serves as a vital transmission provider and generation resource for a variety of utilities in a very large economic region.

Factor 7: Debt Structure and Reserves

In this factor, we consider the utility's debt service reserves, special borrowing arrangements and debt structure. In aggregate, these considerations can result in adjustments ranging from 2 notches down to 2 notches up.

Public power utilities have different approaches to debt service reserve funds. We consider fully funded maximum annual debt service reserve funds to be an important part of revenue bondholder security, particularly during periods of uncertainty in the credit markets. The lack of a debt service reserve fund could result in a downward adjustment of up to one notch. Some utilities have fully cash funded reserves equal to a full year's debt service requirements, others have no debt service reserve fund, and the rest have something in between. For a utility that has less than a full year debt service reserve fund, we also consider the other elements of its liquidity position in determining the level of downward adjustment, which is typically one half or one notch. However, in cases where the utility maintains at least 100 days of liquidity on hand on a sustained basis (see Factor 6: Financial Strength and Liquidity), the downward adjustment may be reduced or eliminated.

Some utilities benefit from preferential borrowing or guarantee arrangements with strong governmental entities. These may provide alternate sources of liquidity, assured borrowing access even when markets are in turmoil, or patient capital that is willing to provide flexibility in the debt terms, e.g. payment-in-kind in lieu of cash interest or deferrable principal payments. When such arrangements are particularly important and are provided by very highly rated government lenders, we may apply uplift of up to two notches.

Most public power utilities primarily use fixed-rate amortizing debt. The use of other types of debt or financing instruments may add meaningful incremental risk that can result in a downward rating adjustment of up to 2 notches. In most cases, the principal risk is an unexpected drain on liquidity resulting, for instance, from short or long-term debt maturities, suddenly higher interest expense, unexpected collateral calls, a decrease in available bank and commercial paper backstop facilities, or market disruptions.

In assessing debt structure, we typically evaluate the existing and projected debt structure, including reliance on short-term debt, bond-covenanted legal protections, the amortization profile (especially bullet, balloon or other large maturities), use of variable rate debt, exposure to interest rate swap agreements, any use of unusual derivatives, and collateral posting requirements. We generally evaluate exposure to unhedged variable rate instruments in relation to the utility's liquidity and its debt management record, including the absolute level of variable rate debt. We may also consider debt management and interest rate swap policies, board oversight of interest rate swaps, and a utility's disclosure of the risks and exposures associated with its debt. Some potential concerns with swaps and other derivatives, depending on their terms, are requirements the utility may face to post mark-to-market collateral and termination rights of the swap counter-party upon occurrence of certain events, such as a downgrade of the utility below a certain rating level. Another important aspect of debt structure is the utility's bond security provisions. Weakness versus the industry norm, for instance a lack of a covenant requiring the utility to set rates sufficient to support a DSCR of at least one times, may lead to a downward adjustment in this factor.

Factor 8: Revenue Stability and Diversity

Revenue stability and diversity considerations include exposure to wholesale power markets and other higher risk businesses, customer concentration and diversity from combined utility operations. In aggregate, revenue stability and diversity considerations can result in adjustments ranging from 2 notches down to one notch up.

In general, public power electric utilities have a very low business risk profile, typically based on their status as monopoly providers of essential services and their ability to set retail rates at a level that allows recovery of all costs, including debt service. Utilities that have meaningful exposure to wholesale power markets or other higher risk businesses (including telephone service) face incremental credit risks, which may include price and revenue volatility, competition, greater liquidity needs and potential asset stranding. Typically, wholesale public power electric utilities sell electricity under long-term power supply contracts with established, financially sound counterparties that ensure cost recovery, and these contracts can insulate them from wholesale markets, provided the counterparty has high credit quality and the contracts can be renewed at maturity. However, some utilities that have excess supply may choose to sell into wholesale energy markets, often utilizing the potentially larger near-term margins earned to limit retail rate increases on native-load retail customers. The latter strategy introduces very meaningful revenue and cash flow volatility, and there is no certainty that wholesale power margins will be achieved, because the price of power and the relative economics of various fuel types can fluctuate widely over time. Wholesale market exposure may be mitigated if the utility has strong liquidity permitting it to withstand a period of lower wholesale energy margins and a timely and transparent rate-setting process that will allow it to recover costs in retail rates when wholesale margins are lower. Material exposure to re-contracting risk, to wholesale purchasers with weak credit quality, to wholesale power markets when mitigants are insufficient, or to other higher risk businesses may result in a downward adjustment of up to 2 notches in this factor.

Large customer concentration can create credit pressure, especially at smaller utilities, because a single large customer (or group of customers in a particular sector) may leave the system without compensating the utility for any outstanding debt used to construct the generation facilities needed to serve that load and may leave the utility with excess power that can only be sold into the wholesale market. Meaningful customer concentration can typically lead to a downward adjustment of one half to one notch in this factor, depending on the level of fixed system costs that would have to be shared with the remaining customer base and the resultant significance of potential rate increases. However, the downward adjustment in this factor may be up to 2 notches in circumstances where a customer is particularly large and engaged in a competitive, cyclical industry or a very weak sector. Customer concentration with a stable university, government, or health care institution may not lead to a downward adjustment unless that customer has a notable weakness.

The presence of other material essential utility services such as water, sewer/wastewater and natural gas in the utility's business mix, i.e. a combined utility enterprise system, may reduce risk by providing revenue diversity that offsets weather-related and seasonal volume fluctuations, or by increasing the enterprise's importance to the municipal owner. When these other utility businesses are well-managed, and depending on the level of diversity and stability they provide, they may result in an upward adjustment of one-half to one notch.

Rating Methodology Assumptions and Limitations, and Rating Considerations That Are Not Covered in the Scorecard

The scorecard in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that would enable the scorecard to map more closely to actual ratings. Accordingly, the eight rating factors in the scorecard do not constitute an exhaustive treatment of all of the considerations that are important for ratings of entities in this sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used for mapping in the scorecard is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we cannot 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 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 access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology scorecard, we did not explicitly include certain important factors that are common to all entities in any industry such as the quality and experience of management, assessments of governance and the quality of financial reporting and information disclosure. Therefore, ranking these factors by rating category in a scorecard 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 or other political interference in some jurisdictions. 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 to precisely express these in the rating methodology scorecard without making the scorecard 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 scorecard.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the scorecard. 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, unless these are low rated companies for which liquidity can be a substantial differentiator for relative default risk.

Other Rating Considerations

Ratings encompass a number of additional considerations. These include but are not limited to: the impact of non-core businesses, our assessment of the quality of management, governance, financial controls, liquidity management, event risk, size, and interaction of ratings with government policies and sovereign ratings.

Impact of Non-Core Businesses

This methodology scorecard is applied to the assessment of issuers whose primary activity is operating a US public power electric utility with generation ownership exposure. Where the utility has or will seek to diversify its operations towards other business types, we consider the impact of such diversification on credit quality. In particular, the ownership of material businesses with a higher credit risk than a US public power electric utility with generation ownership exposure would likely result in an actual rating that is lower than the scorecard-indicated rating.

Management Strategy

The quality of management is an important factor supporting any issuer's credit strength. 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.

Governance

Among the areas of focus in governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, ownership structure and working relationship between the board, government stakeholders (e.g., city councils) and management teams.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. The quality of financial statements may be influenced by internal controls, including centralized operations and the proper tone at the top and consistency in accounting policies and procedures. Auditors' comments in financial reports and unusual financial statement restatements or delays in regulatory or other required filings may indicate weaknesses in internal controls.

Liquidity Management

Liquidity is an important rating consideration for all US public power electric utilities with generation ownership exposure. We form an opinion on likely near-term liquidity requirements from the perspective of both sources and uses of cash. While liquidity is specifically considered in certain scorecard factors, when it is very weak, the impact it has on ratings may be much greater than the standard weights for these factors would otherwise imply.

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 could include, asset sales, mandated changes in business activities, capital restructuring programs, litigation and material changes that increase payments in lieu of taxes or other similar distributions by the utility to the municipality.

Size

The size and scale of a US public power electric utility with generation ownership exposure has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. However, size can still be a very important factor in our assessment of certain risks that impact ratings, including natural and man-made disasters, event risk, construction risk and access to external funding. While construction risk is specifically considered in certain scorecard factors, when it is very high relative to the size of the utility, the impact it has on ratings may be much greater than the standard weights for these factors would otherwise imply.

Interaction of Ratings with Government Policies and Sovereign and Sub-Sovereign Ratings

Compared to most industrial sectors, US public power electric utilities with generation ownership exposure are more likely to be impacted by government and related political actions. Credit implications can occur directly through regulation, and indirectly through energy, environmental and tax policies.

Appendix: US Public Power Electric Utilities with Generation Ownership Exposure Methodology Factor Scorecard

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Cost Recovery Framework Within Service Territory	25%	Monopoly with unregulated rate setting and very strong customer base and service area economy	Monopoly with unregulated rate setting and strong customer base and service area credit economy	Monopoly with unregulated rate setting; average customer base and service area economy	Regulation of rates by state; weak customer base / service area economy	Regulation of rates by state with some inconsistency; or very weak customer base or service area economy	Regulation of rates by state is unpredictable; or extremely weak customer base or service area economy

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Willingness and Ability to Recover Costs with Sound Financial Metrics	25%	Excellent rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments less than 10 days; No political intervention in past or extremely high support from related government; Very limited General Fund transfers governed by policy	Strong rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments 10 to 30 days; Limited political intervention in past or high support from related government; Conservative and well-defined General Fund transfers governed by policy	Adequate rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments 31 to 60 days; Some political intervention in past or average support from related government; Moderate General Fund transfers	Below average rate-setting record; Rates, fuel, & purchased power cost adjustments 61 to 99 days; Persistent political intervention or below average support from related government; Large General Fund transfer not governed by policy	Some history or expectation of insufficient rate-setting; Rates, fuel, & purchased power cost adjustments 100 to 120 days; Highly political climate or very limited support from related government; Sizeable General Fund transfer not governed by policy	Lengthy record of, or expectation for a prolonged period of insufficient rate-setting ; Rates, fuel, & purchased power cost adjustments 120 days or more; Highly contentious political climate or clear lack of support from related government; Very sizeable General Fund transfer not governed by policy

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Generation and Power Procurement Risk Exposure[13]	10%	Very limited exposure to negative repercussions from generation, procurement and commodity price risks; High degree of diversification of generation and/or fuel sources; Single generation asset typically provides less than 20% of power; or up to 20% of energy from coal-fired generation with carbon mitigation strategy	Limited exposure to negative repercussions from generation, procurement and commodity price risks; Some diversification of generation and/or fuel sources; Single generation asset typically provides less than 40% of power; or up to 40% of energy from coal-fired generation with carbon mitigation strategy	Moderate exposure to negative repercussion from generation, procurement and commodity price risks; Some reliance in one type of generation and/or fuel source, but diversified with purchased power sources; Single generation asset may provide up to 55% of power; or up to 55% of energy from coal-fired generation with carbon mitigation strategy	Moderate to high exposure to negative repercussion from generation, procurement and commodity price risks; Reliance on a single type of generation or fuel source, with somewhat limited diversification via purchased power; Single generation asset typically provides up to 75% of power; or up to 70% of energy from coal-fired generation with carbon mitigation strategy	High exposure to negative repercussion from generation, procurement and commodity price risks; Very high concentration in a single type of generation or very high reliance on a single fuel source, with limited diversification via purchased power; Single generation asset typically provides up to 75% of energy from coal-fired generation with carbon mitigation strategy, or up to 50% of energy from coal with no mitigation strategy	Very high exposure to negative repercussion from generation, procurement and commodity price risks; very high concentration in a single type of generation, almost entirely reliant on a single fuel source, with very limited diversification via purchased power; Single generation asset typically provides over 85% of power; or over 85% of energy from coal-fired generation with carbon mitigation strategy, or over 50% of energy from coal-fired generation with no mitigation strategy

13 In scoring this factor, generation includes generation from owned assets and via participation in Joint Action Agencies, unit power arrangements and similar arrangements.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Competitiveness	10%	Extremely competitive current and expected rates[14] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates more than 25% below state average); and virtually no material prospective cost pressures that could lead to higher rates	Very competitive current and expected rates[14] in the state and/or compared to neighboring utilities on a consistent basis (e.g. average system rates in a range of 7.5% to 25% below state average); very low likelihood of material prospective cost pressures that could lead to higher rates	Competitive current and expected rates[14] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 7.5% below state average to 7.5% above state average); modest likelihood of material prospective cost pressures that could lead to higher rates	Somewhat competitive current and expected rates[14] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 7.5% to 25% above state average); high likelihood of material prospective cost pressures that could lead to higher rates	Uncompetitive current or expected rates[14] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 25% to 35% above state average); or high likelihood of imminent, material cost pressures that could lead to higher rates	Extremely uncompetitive current or expected rates[14] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates more than 35% above state average); or currently in a period of persistent cost pressures that are causing material rate increases

Financial Strength and Liquidity	Weight	Aaa	Aa	A	Baa	Ba	B
Adjusted days liquidity on hand[15] (3-year avg) (days)	10%	≥ 250	150 - 250	90 - 150	30 - 90	15 - 30	< 15
Debt ratio (3-year avg)[16] (%)	10%	< 35%	35% - 60%	60% - 75%	75% - 90%	90% - 100%	≥ 100%
Adjusted Debt Service Coverage[17] OR Fixed Obligation Charge Coverage[18] (3-years avg) (x)	10%	≥ 2.5x	2x - 2.5x	1.5x - 2x	1.1x - 1.5x	1x - 1.1x	< 1x

14 Retail rates are typically calculated as average revenue per kilowatt hour sold; however, this factor may also be assessed based on competitive positioning of rates in a dominant customer class (residential, commercial, industrial or wholesale).

15 Defined as: (Available unrestricted cash and investments + Eligible unused bank lines and capacity under commercial paper programs) x 365 days / (Utility's annual operating and maintenance expenses exclusive of depreciation and amortization expenses and the debt service portion of annual payments made to JAAs under take-or-pay contracts). For the numerator, certain designated reserves (but excluding debt service funds and reserve requirement) that are available when needed by the utility are included in unrestricted cash and investments. The unused portion of eligible bank lines are included. Capacity under commercial paper programs is included without duplication to unused eligible bank lines. To be included in this ratio, eligible bank lines must meet all of the following criteria:

» Committed facilities
» Remaining tenor of committed drawdown availability is at least one year
» Absence of impediments to drawdown, including:
  - No material adverse change (MAC) representation requirement for borrowings
  - No material adverse litigation (MAL) representation requirement for borrowings
  - No covenants set at a level reasonably expected to restrict borrowings
» If bilateral, provided by a bank rated P-1
» If syndicated, provided by a group of banks predominantly rated P-1

16 Defined as: (Gross debt – Debt service funds – Interest payable and debt service reserve funds) / (Gross fixed plant assets –Accumulated depreciation on plant + Net working capital). Net working capital is defined as cash and investments plus receivables expected to be collected minus current liabilities unrelated to debt.

17 Defined as: (Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFTs) / Aggregate annual debt service. In the numerator, recurring revenue and recurring expenses exclude special, one-time items. Annual cash operating expenses exclude depreciation and amortization expenses. GFTs are general fund transfers.

18 Defined as: (Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFT + Debt service portion of annual payments made to JAAs under take-or-pay contracts) / (Aggregate annual debt service + Debt service portion of annual payments made to JAAs under take-or-pay contracts).

Factors 1-5 Preliminary Scorecard-Indicated Rating

Factors 6, 7, and 8 These factors result in upward or downward adjustments to the preliminary scorecard-indicated rating resulting from factors 1-5. In aggregate, these factors can result in a total of 3 notches up or down from the preliminary scorecard-indicated rating to arrive at the scorecard-indicated rating.
Factor 6: Operational Considerations Operational considerations include construction risks and whether the utility is a vital service provider. In aggregate, operational considerations can result adjustments ranging from 2 notches down to one notch up. Construction Risks: up to 2 negative notches Vital Services to a Very Large Economic Region: up to one positive notch
Factor 7: Debt Structure and Reserves In this factor, we consider the utility's debt service reserves, special borrowing arrangements and debt structure. In aggregate, these considerations can result in adjustments ranging from 2 notches down to 2 notches up. Debt Service Reserves: up to one negative notch Preferential Borrowing/Guarantee Arrangements: up to 2 positive notches Debt Structure: up to 2 negative notches
Factor 8: Revenue Stability and Diversity Revenue stability and diversity considerations include exposure to wholesale power markets and other higher risk businesses, customer concentration and diversity from combined utility operations. In aggregate, revenues stability and diversity considerations can result adjustments ranging from 2 notches down to one notch up. Exposure to Wholesale Power Markets and Other Higher Risk Businesses: up to 2 negative notches Customer Concentration: up to 2 negative notches Revenue Diversity: up to one positive notch

Scorecard-Indicated Rating

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 and Definitions, which is available here for further information.

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OUTLOOK
6 December 2018

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Public power electric utilities - US

2019 outlook stable, aided by sound cost recovery, adaptability to clean energy shift

The outlook for business conditions in the US public power electric utility sector over the next 12-18 months is stable, supported by self-regulated cost recovery, sound financial metrics and a competitive product. Challenges include the transition to clean energy, continuing efforts to reduce greenhouse gas emissions, cybersecurity risks and lower electricity demand, but we think the sector can adapt to them.

» **Utilities' financial position will remain healthy in 2019.** Public power utilities continue to show a trend of stable to modestly improving metrics, including the median fixed obligation charge coverage (FOCC), which we expect to remain in the 1.80x-1.90x range. Leverage will decline from the current 60% debt ratio for the largest 50 utilities, and liquidity will remain strong at 200-250 days on hand.

» **Cost recovery remains a core strength, but power resource issues are challenges.** Cost recovery through self-regulated rate setting has been a resilient model. But some utilities face recovery and litigation issues due to new construction and power resource decisions, which could test this core strength. Also, lower electric demand and wider access to competitive energy sources and contracted renewables have made utilities more reliant on wholesale markets and third parties, raising exposure to market risk.

» **Industry transition will vary by region.** California's utilities are focused on meeting state requirements to lower greenhouse gas emissions or increase renewables use. Utilities in the Southeast support maintaining baseload generation, but some face difficulties in completing and securing recovery for complex projects, such as the Vogtle Nuclear Units and 3 and 4.

» **Utilities will continue to push ahead with clean energy plans.** Despite federal and some state governments easing enforcement of existing environmental policies, we expect public power utilities will continue establishing clean energy strategies because of the declining costs and more reliable performance of most renewable assets.

» **Cyber security attacks are an increasing concern.** As infrastructure becomes more digitized and interconnected, cyber breaches are a growing challenge for utilities, which are stepping up cyber security training and efforts to comply with federal standards.

» **What would change our outlook** Our outlook for the sector could change to negative if technological advances impact the willingness of governing boards to raise electric rates, leading to the FOCC declining to 1.50x. We could change the outlook to positive if the sector adapts well to industry changes and the median FOCC ratio exceeds 2.0x.

Moody's industry outlooks represent our forward-looking view on business conditions that factor into our ratings; a negative (positive) outlook suggests that negative (positive) rating actions are more likely on average. The industry outlook does not represent a sum of upgrades, downgrades or ratings under review, or an average of the rating outlooks of issuers in the industry, but rather our assessment of the main direction of business fundamentals within the overall industry.

Introduction

The US public power electric utility sector includes over 2,000 municipal electric utilities, primarily small distribution systems, though some own their own electric generation and transmission assets, including South Carolina Public Service Authority (A2 negative) or Orlando Utilities Commission, Florida (Aa2 stable). Most of the revenue bond debt outstanding in the sector is issued by those owning electric generation. About 15% of US electricity customers are served by public power electric utilities in cities including the City of San Antonio (Aaa stable), Seattle (Aaa stable) and Cleveland, Ohio (A1 issuer rating, stable). The strong attributes of these utilities include self-regulation on rate setting, issuance of tax-exempt debt, and near monopoly control of their customer base.

The US public power electric utilities we rate include joint power agencies (JPAs), which are made up of groups of municipal electric utilities that jointly finance electricity generation or transmission projects. Also included is a new form in California called Community Choice Aggregators (CCAs), which have many of the same characteristics of municipally owned electric utilities.

Assumptions we incorporated in our analysis of the business environment

» The public power business model, including local governance and self-regulated cost recovery, will remain intact in 2019.

» Public power electric utilities will continue to adapt to regional energy markets. We do not expect regional energy markets to fail, but we do expect continued economic pressure on baseload coal and nuclear assets due to lower regional energy prices through 2019.

» Growth in US gross domestic product will be 2.3% in 2019, with unemployment at 4%, according to Moody's Macroeconomic board, indicating a stable business environment.

» There will be several small interest rate adjustments by the Federal Reserve, and normalization of the Federal Reserve balance sheets will proceed through 2019, according to Moody's Macroeconomic board.

» Natural gas prices seem to have stabilized around $3.00 per MMBtu at Henry Hub through 2019, according to Moody's forecasts.

» Delivered coal prices will remain stable, according to the Energy Information Administration (EIA).

» Federal tax credits and technological advances should maintain improving economics for renewable energy.

» Delivered electricity demand is expected to increase by 0.8% in 2019, according to EIA.

Utilities' financial position will remain healthy in 2019

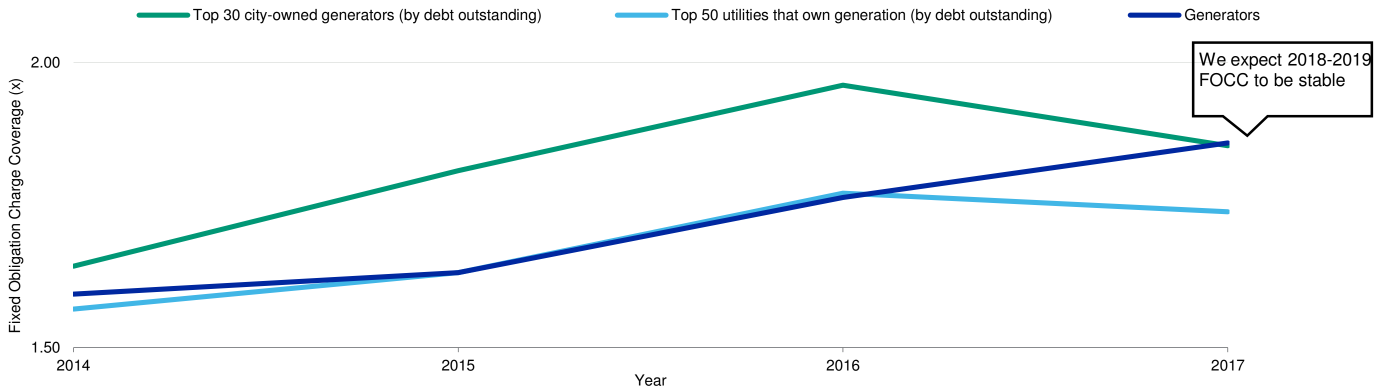
US public power electric utilities will continue to display a trend of stable to modestly improving financial metrics, supported by a steady business environment and their self-regulated ability to set electricity rates to pay debt service.

Debt coverage ratios will stay strong

For 2019, we expect the fixed obligation charge coverage (FOCC) ratio will remain strong, in the 1.80x-1.90x range, as shown in Exhibit 1. The FOCC ratio indicates the resilience of a utility's financial operations and results that ensure debt service is paid in a timely way.

Exhibit 1

Fixed obligation charge coverage for public power utilities remains strong



Source: Moody's Investors Service

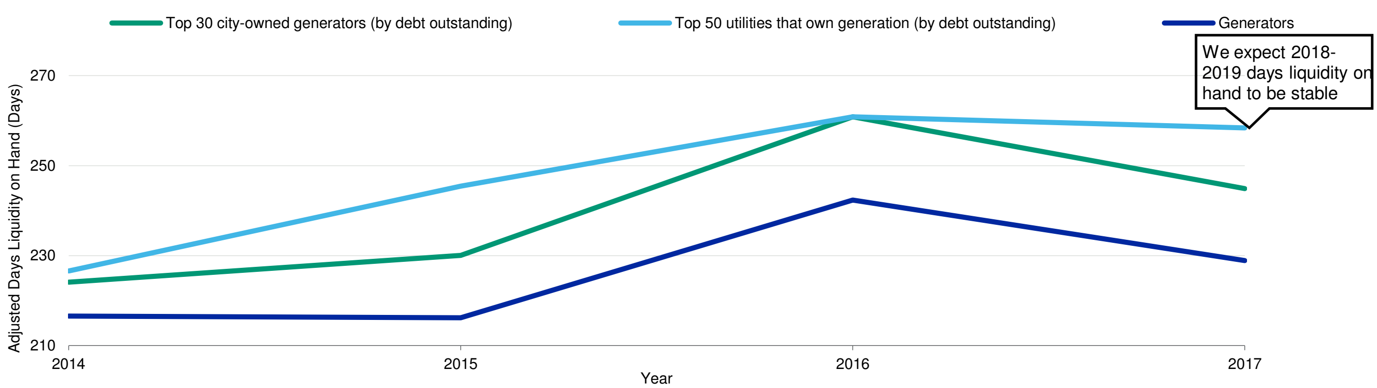
Our calculation of a utility's FOCC incorporates the utility's payment of a share of surplus revenues to a city's general fund as an operating expense and the utility's payment to a joint power agency for debt service if it participates in such a transaction. General fund transfers have moderated in the past several years and we expect this trend to continue, particularly in California where taxpayer litigation has all but constrained revenue transfer increases to the general government.

Financial liquidity will remain healthy

We expect that strong financial liquidity will be maintained in 2019, in the range of 200-250 days liquidity on hand for public power electric utilities that own generation, as shown in Exhibit 2.

Exhibit 2

Trend of sound liquidity continues in the public power sector



Source: Moody's Investors Service

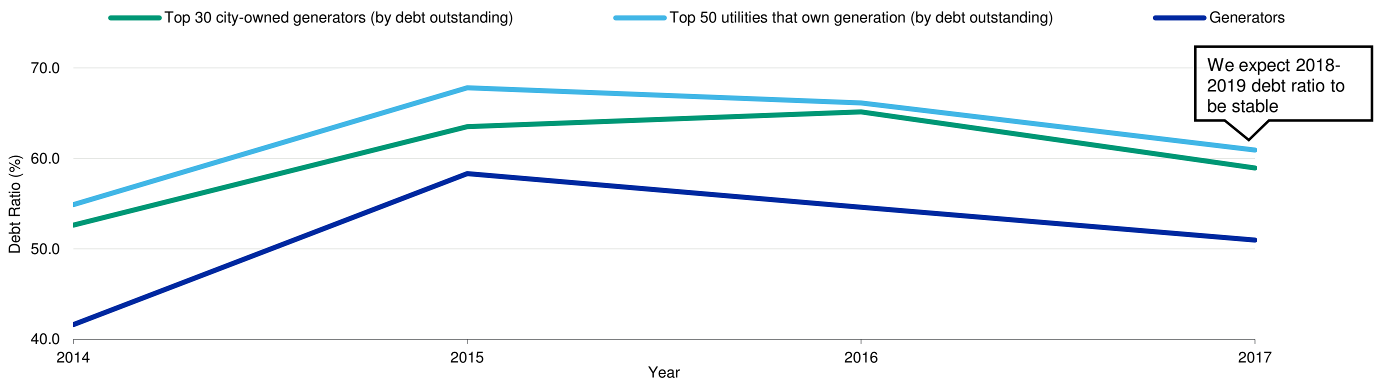
These utilities typically maintain most financial liquidity internally, with reserves for various purposes, from rate stabilization accounts to contingency reserves. Many also have external sources of liquidity such as unused commercial paper or bank lines of credit. Sufficient liquidity is a credit positive factor that can be used to mitigate the impact of hurricane disasters, unexpected fuel or power price increases, or budget variances due to generation outages. Sound liquidity helped many public power electric utilities in the Southeast manage the initial operational and financial impact of Hurricane Florence in 2018.

Debt ratios will continue to moderate

Debt leverage will continue to moderate from the current 60% ratio for the largest 50 public power electric utilities, as shown in Exhibit 3 (the public power electric utility generators' median ratio is 50%). With customer demand continuing to moderate through implementation of energy efficiency measures, most utilities forecast slower demand growth, which together with more contracted purchased power resources and scheduled amortization, has led to a decline in the need for debt financing for new construction.

Exhibit 3

Public power electric utilities' debt ratios will continue to moderate



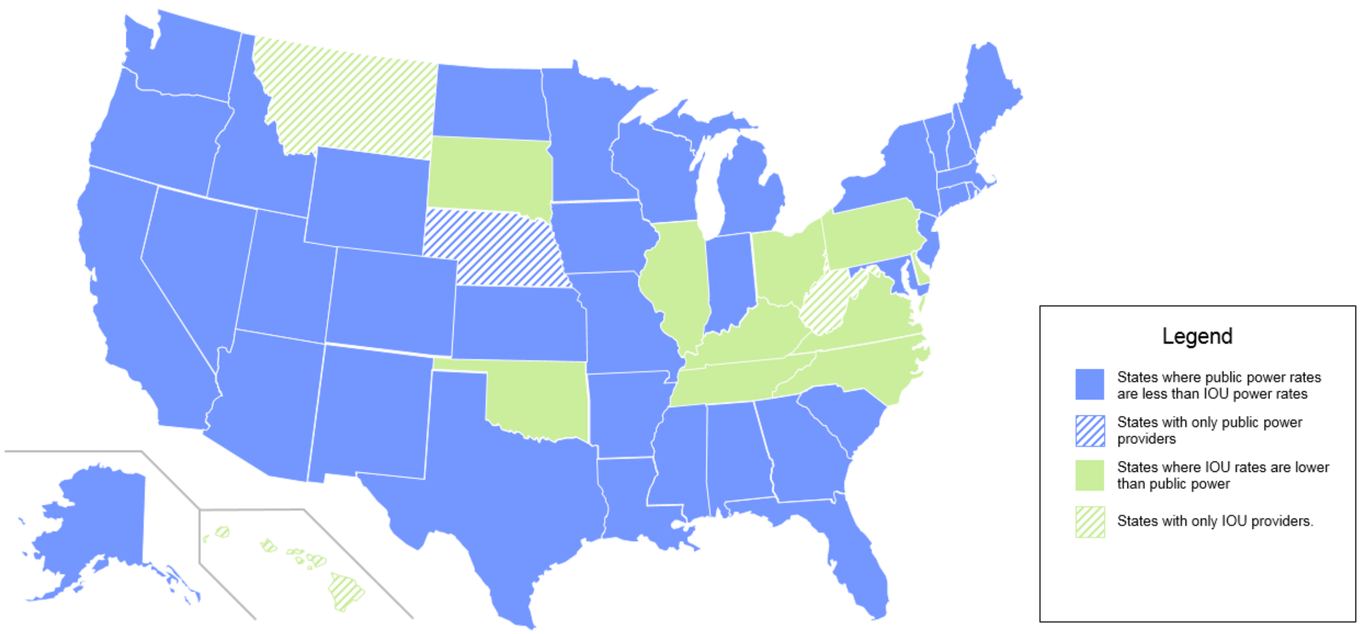
Source: Moody's Investors Service

Sector's pricing will remain competitive

Prices charged by utilities will remain competitive in 2019. In 2017, public power utilities in three quarters of states had lower customer rates than investor-owned utilities, as shown in Exhibits 4 and 5. Since most public power utilities transfer a portion of surplus revenue to the general government, the competitive advantage is reduced, but the transfers are used for general city services.

Exhibit 4

In 2017, public power utilities in most states had lower customer rates than investor-owned utilities



78% of US states have lower municipal utility residential rates compared to IOU prices. This percentage excludes the states that do not have both public power or IOUs.

Source: Moody's Investors Service

Exhibit 5

Most of the top 10 public power electric utilities offer lower retail rates than other utilities (1)

Utility	Location	Utility retail rates - residential (cents/kWh)	Investor owned utility average retail rates - residential (cents/kWh)
Salt River Project (SRP) (2)	Arizona	11.59	11.06/ 13.57
CPS Energy (3)	Texas	11.04	11.05 /12.13
Los Angeles Department of Water and Power	California	16.65	19.21
Nebraska Public Power District (NPPD) (4)	Nebraska	10.75	--
Omaha Public Power District (OPPD) (4)	Nebraska	11.49	--
JEA	Florida	11.43	12.72
PUD No. 2 Grant County	Washington	5.41	10.10
Chelan County PUD No. 1	Washington	3.17	10.10
Austin Energy	Texas	10.70	11.05
Sacramento Municipal Utility District (SMUD)	California	14.06	19.21

(1) Top 10 public power retail systems ranked by generation, excluding wholesalers
(2) $13.57 represents the price for direct competitor of SRP
(3) $12.13 represents the price for direct competitor of CPS Energy
(4) Only public power utilities serve at retail in Nebraska
Source: Moody's Investors Service; EIA-861, 2017

Cost recovery will remain a core strength, but power resource issues present challenges

A distinguishing credit fundamental of the public power sector is cost recovery through self-regulated local rate-setting, and we expect the model will remain in place in 2019-20. However, a few public power electric utilities face resource planning, construction and related recovery and litigation challenges in 2018 and 2019 owing to decisions on power resources, and these ultimately may test the resilience of the business model and its ability to recover costs on a timely basis.

Gainesville Utilities Commission (GRU, Aa3 stable) has faced political pressure due to its previous investment in a now uneconomic, carbon-neutral biomass generation facility. A ballot measure in 2018 seeking to change the way GRU was governed and to create better oversight of such decision-making was not approved, but it highlights how the transition to new sources of carbon-neutral energy has affected some utilities. Austin Energy, Texas (Aa3 stable) invested in a $2.3 billion contract for energy from a biomass generation facility that has subsequently been idled since 2012 due to the competitive energy markets in Texas. Austin Energy has an annual capacity payment despite not receiving energy, which represents a financial burden and lowers coverage ratios.

The aftermath of Santee Cooper's decision to stop construction of the Summer 2 and 3 nuclear projects left it with $4 billion of revenue bonds outstanding as well as political pressure to hold it accountable for the stranded project and its cost to ratepayers. The original construction decision was partly based on the utility's carbon reduction plan. Proposals ranging from selling the utility to regulating it are currently under consideration. While Santee Cooper maintains its competitive position and self-regulation ability, its future remains uncertain owing to the outstanding nuclear debt and ongoing litigation.

Likewise, the Mayor of Jacksonville, FL, in 2018 brought to City Council a plan to privatize JEA (A2 negative), one of the nation's largest municipal utilities. Although privatization efforts were ultimately formally suspended, this underscores the risk to the business model as utilities face competitive and industry transition pressures.

Reliance grows on wholesale market and third-party providers for supply

Other power resource decisions by public utilities have continued a departure from longer-term supply strategies. Though beneficial in the short term, this might lead to new challenges for the existing business model, with the sector becoming more dependent on the wholesale market or third-party providers. Specifically, lower demand growth and new contracted renewable energy supplies have resulted in public power utilities becoming more reliant on contracted supply and day-ahead regional energy markets and less on locally owned generation.

Access to low energy prices in regional markets has provided an important advantage for many utilities in 2018, and we expect this trend will carry over into 2019. This development is also reflected in the sector's reduced leverage as utilities contract for energy rather than build and debt-finance new energy sources. However, if challenges arise such as a regional energy market failure or an unexpected spike in natural gas prices, it could result in additional costs to ratepayers and credit instability if there is limited local generation and a lack of fuel diversity to mitigate such developments.

An example of long-term power resource planning uncertainty is Nebraska Public Power District (NPPD, A1 stable), which has several long-term strategic questions before it. NPPD currently has a well-diversified power supply portfolio with nuclear, coal, natural gas and renewable energy sources and annually generates and sells significant amounts of excess energy into the market to help keep customer power costs low. With management focused on reliability and low costs, NPPD's resource profile continues to serve customers well and provides the district with multiple strategic options for its long-term power supply needs.

However, as NPPD's generation plants age to their useful life, decisions lie ahead on whether to replace or retool older baseload plants, how much to rely on regional energy markets, whether to add new natural-gas-fired generation, and if the transmission system can manage additional energy intermittence due to the larger role played by renewable energy—a question that will be further complicated as battery storage technology improves and is integrated into the grid. NPPD management will be tested by these issues but we expect them to be able to adapt to the long-term transition.

Industry transition challenges will vary by region

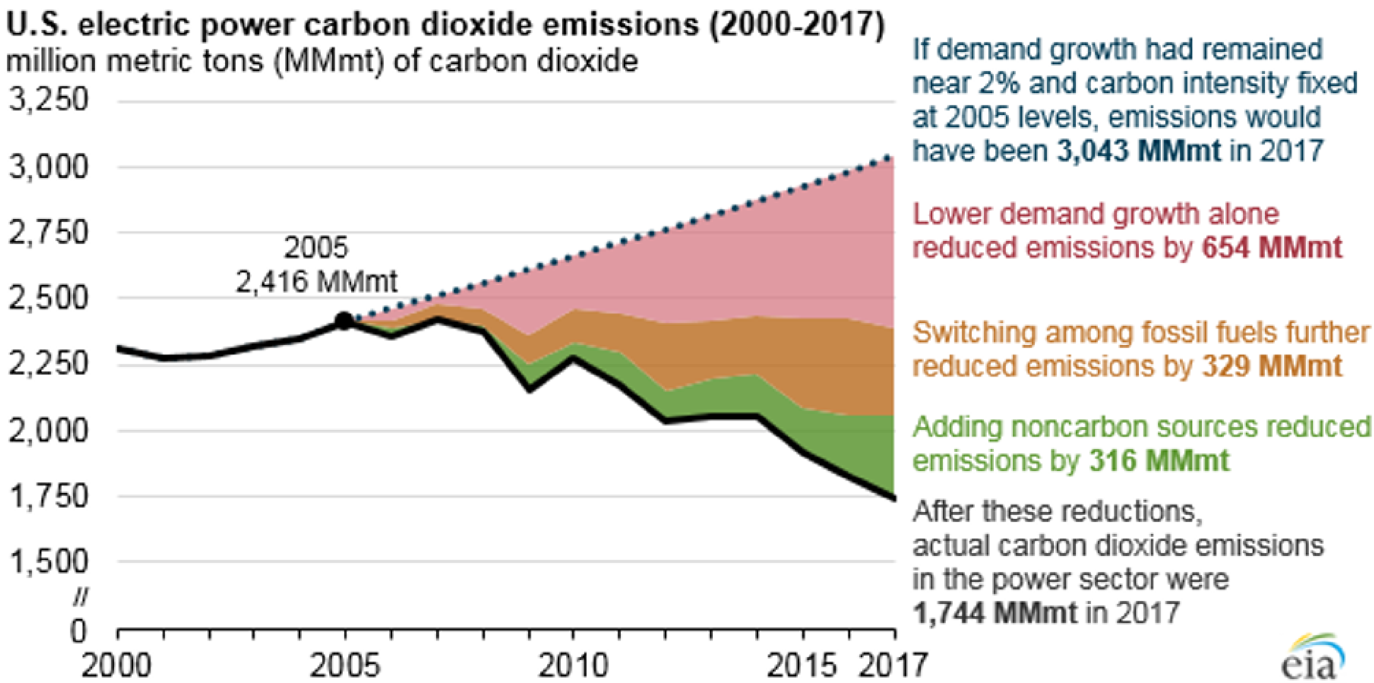
As the industry undergoes transition, one size does not fit all from a regional perspective, with utilities facing different risks and opportunities depending on what part of the country they are located in. For example, credit pressures on public power electric utilities in California have increased as they face numerous state requirements and more immediate compliance timetables for lowering greenhouse gas emissions or adding more renewables. Further actions will be needed in 2019 to meet state regulatory requirements. California has established by statute an objective that 100% of energy supplied to retail customers comes from renewable sources by 2045. While that is 27 years away, the statute stipulates that in the meantime the percentage of renewables should increase each year. Other unique issues facing California's power industry include the credit impact of the state's potential restrictions on new natural-gas-fired generation projects, the impact of wildfires on utility credit quality, and the growing role of CCAs.

In the Southeast, by contrast, utilities have been strongly supportive of maintaining baseload generation to ensure power reliability, but some face difficulties in completing and securing recovery for complex baseload projects such as the Summer 2 and 3 and Vogtle Nuclear Units 3 and 4. In Texas and Florida, natural gas now accounts for 60% of the fuel mix so a disruption in fuel delivery or price would have outsized risks. In the Midwest and Southeast, where coal-fired generation represents a substantial portion of the fuel mix, carbon transition risks will be greater.

Utilities will continue to push ahead with clean energy plans

Despite federal and some state governments easing enforcement of existing environmental policies, we expect public power utilities will continue to establish clean energy and carbon reduction strategies, helped by lower energy demand, greater use of natural gas, and the declining costs and more reliable performance of most renewable assets. Exhibit 6 shows the factors going into lower carbon levels. We expect this trend will continue over the next 12-18 months, with the lower prices for natural gas and contracted renewable energy being major contributors.

Exhibit 6



Source: US Energy Information Administration, US energy-related carbon dioxide emissions, 2017

We believe that most of the legislative actions on carbon reduction will occur at the state level. The Trump administration's executive order to revise the federal Clean Power Plan (CPP) has resulted in a proposed rule that, in relation to carbon reduction, is modest compared with the original CPP. The new rule would require lower heat rates at fossil fuel generation facilities, which would burn coal more efficiently and use less fuel, thus reducing carbon emissions. Should the rule go into effect, utilities have two years to come up with a plan. In the meantime, the most efficient coal-fired power plants will continue to be dispatched, while other units that need new investment or face further idling due to an inability to be economically dispatched may be shut down.

Public power electric utilities continue to push forward clean energy plans. Exhibit 7 shows a select list of rated public power electric utilities that have set a goal of 100% renewable energy use. Except in California, the goals are not legislated or regulated requirements but more in the way of planning guidelines, which vary between utilities. While not yet at a 100% objective, Austin's Energy Resource, Generation and Climate Protection Plan, for example, requests that every city department ensure that its operations are in line with the plan's objectives, including a goal of reaching 65% renewable energy by 2027, with 100% as an aspiration. Long Island Power Authority (A3 stable) and New York Power Authority (Aa1 stable) are focused on New York State's Climate Plan, which involves 50% of electricity generated in New York being supplied by renewable energy sources by 2030; 2.4 gigawatts of offshore wind by 2030; a reduction of greenhouse gas emissions by 40% by 2030; and an energy storage target of 1,500 MW by 2025.

Exhibit 7

Rated US public power electric utilities that have a goal of 100% renewable energy

City	% Renewable	Year
Cleveland, Ohio	100%	2050
Fort Collins, Colorado	100%	2030
Gainesville, Florida	100%	2045
Orlando, Florida	100%	2050
Burlington, Vermont	100%	2014
Rochester, Minnesota	100%	2031
Traverse City, Michigan	100%	2040
Anaheim, California (1)	100%	2045
Los Angeles, California (1)	100%	2045
Sacramento, California (1)	100%	2045
Glendale, California (1)	100%	2045
Roseville, California (1)	100%	2045
Imperial, California (1)	100%	2045
Modesto, California (1)	100%	2045
Turlock, California (1)	100%	2045
Vernon, California (1)	100%	2045

(1) California SB 100 requires cities to be at 100% renewable energy by 2045. The cities included in this list fall within the Top 50 largest utilities in the Appendix
Source: Moody's Investors Service

Technological advances such as in battery storage and electric vehicles (EVs) will add uncertainty to resource procurement depending on pace of their development

Battery storage

Advances in battery storage have so far been mostly at the residential customer level. Given that the scale needed for utility power storage projects has not yet developed, we do not expect batteries to achieve a significant breakthrough in 2019. But since power resource procurement or construction is often a multiyear process, this creates planning uncertainties, particularly for utilities that need to balance new renewables-based generation. For example, a significant question under consideration in California is whether utility power storage projects can replace natural-gas-fired generation facilities that serve to mitigate the intermittent nature of solar and wind.

Battery storage will, however, ultimately prove to be an important development for the public power sector if it helps increase reliability and manage costs. Many states, such as California, New York, Nevada and Oregon, are including energy storage incentives as part of long-term strategies. Some state public utility commissions now require that utilities include energy storage in integrated resource plans. California has been at the forefront of implementing storage systems. As part of its long-term resource plan, Los Angeles Department of Water and Power (LADWP, Aa2 stable) has included 404 MW of energy storage by 2025.

Electric vehicles

We do not see the expansion of electric vehicles having any material impact on demand for electricity in 2019. According to a recent report by McKinsey & Co., electric vehicles will add about 1% to total demand on the grid, requiring about 5 GW of new generation capacity by 2030. However, utilities that have a strong focus on renewable energy, such as Austin Energy, Sacramento Municipal Utility District and Salt River Project, now tend to include EV developments in their strategies, offering EV charging stations, financial incentives and EV price plans for customers in an effort to position themselves better for future demand growth stemming from EVs.

Cyber risk is an increasing concern

As infrastructure becomes more digitized and interconnected, utilities face growing risks of cyber security breaches, with the new threats becoming increasingly sophisticated and requiring continuing vigilance. Smaller utilities are as vulnerable as larger ones.

The sector is taking an increasingly proactive stance on training and on efforts to comply with federal cyber security standards. Snohomish County Public Utility District (Aa3 stable) in Washington, for example, invited the state's National Guard, which includes employees of major technology firms as members, to attempt to hack the utility in a hands-on exercise. The American Public Power Association has established an online Public Power Cybersecurity Scorecard, which is a cyber security self-assessment process to identify improvements.

While we expect that such pro-active measures will continue in 2019, cyber attacks remain a growing risk, and existing federal compliance standards remain insufficient by themselves to address the dangers. Maintaining sound credit quality for public power utilities will require not only a continued focus on mitigating cyber risks but also a plan to ensure that, in case of a breach, recovery can take place on a timely basis. This might involve the use of cybersecurity insurance and the maintenance of strong liquidity.

What would change our outlook

Our outlook for the sector could be changed to negative if technological advances impact the willingness of governing boards to raise electric rates, leading to the FOCC dropping to 1.50x. We could change the outlook to positive if the sector adapts well to the industry changes outlined above and the median FOCC ratio exceeds 2.0x.

Appendix

Exhibit 8
Largest 50 US public power electric utilities by debt outstanding

Public Power Utility	Senior Rating	Outlook	Debt Outstanding ($'000)
Tennessee Valley Authority	Aaa	Stable	25,253,000
Bonneville Power Administration, WA	Aa1	Stable	15,300,400
Long Island Power Authority, NY	A3	Positive	9,747,480
Los Angeles Department of Water & Power, CA Electric Enterprise, CA	Aa2	Stable	9,073,453
South Carolina Public Service Authority, SC	A2	Negative	7,877,998
San Antonio (City of) TX Combined Utility Enterprise, TX	Aa1	Stable	5,542,985
Salt River Project Agricultural Improvement and Power District, AZ	Aa1	Stable	4,079,263
Lower Colorado River Authority, TX	A2	Stable	3,563,000
Sacramento Municipal Utility District, CA	Aa3	Stable	2,523,775
New York State Power Authority, NY	Aa1	Stable	2,451,000
Seattle (City of) WA Electric Enterprise, WA	Aa2	Stable	2,345,500
JEA, FL	A2		2,306,410
Colorado Springs (City of) CO Combined Utility Enterprise, CO	Aa2	Stable	2,264,617
Omaha Public Power District, NE	Aa2	Stable	2,132,253
LCRA Transmission Services Corporation, TX	A1	Stable	1,875,100
Gainesville (City of) FL Combined Utility Enterprise, FL	Aa3	Stable	1,871,709
Nebraska Public Power District, NE	A1	Stable	1,740,957
Orlando Utilities Commission, FL	Aa2	Stable	1,437,025
Austin (City of) TX Electric Enterprise, TX	Aa3	Stable	1,350,741
Grant County Public Utility District 2, WA	Aa3	Stable	1,330,270
Turlock Irrigation District, CA	A2	Stable	1,074,393
Grand River Dam Authority, OK	A1	Stable	982,330
Anaheim (City of) CA Electric Enterprise, CA	Aa3	Stable	705,526
Unified Government of Wyandotte County/Kansas City,KS Combined Utility Enterprise, KS	A2	Stable	695,100
Modesto Irrigation District, CA	A2	Stable	654,335
Guam Power Authority, GU	Baa2	Negative	614,499
Chelan County Public Utility District 1, WA	Aa3	Stable	542,000
Imperial Irrigation District, CA Electric Enterprise, CA	A1	Stable	530,590
Springfield (City of) IL Electric Enterprise, IL	A3	Stable	517,255
Tallahassee (City of) FL Electric Enterprise, FL	Aa3	Stable	507,266
Snohomish County Public Utility District 1, WA Electric Enterprise, WA	Aa3	Stable	471,965
Tacoma (City of) WA Electric Enterprise, WA	Aa3	Stable	404,610
Lakeland (City of) FL Electric Enterprise, FL	Aa3	Stable	384,864
Vernon (City of) CA Electric Enterprise, CA	Baa3	Stable	367,830
Clark County Public Utility District 1, WA	A1	Positive	358,045
Lansing Board of Water & Light, MI	Aa3	Stable	324,667
Memphis (City of) TN Electric Enterprise, TN	Aa2	Stable	312,685
Fayetteville Public Works Commission, NC	Aa2	Stable	288,849
Brownsville Public Utility Board, TX	A2	Stable	279,650
Bryan (City of) TX Electric Enterprise, TX	A2	Stable	229,450
Roseville (City of) CA Electric Enterprise, CA	A1	Stable	219,635
Rock Hill (City of) SC Combined Utility Enterprise, SC	A3	Stable	202,235
Cleveland (City of) OH Electric Enterprise, OH	A3	Stable	202,173
Lafayette (City of) LA Combined Utilities Enterprise, LA	A1	Stable	195,915
Eugene Water & Electric Board, OR Electric Enterprise, OR	Aa2	Stable	191,990
Owensboro (City of) KY Electric Enterprise, KY	A3	Stable	188,843
Cowlitz County Public Utility District 1, WA	A1	No Outlook	185,051
Rochester (City of) MN Electric Enterprise, MN	Aa3	Stable	182,365
Holland (City of) MI Electric Enterprise, MI	Aa3	Stable	158,840
Douglas County Public Utility District 1, WA	Aa3	Stable	158,346

Source: Moody's Investors Service

Moody's related publications

Rating Methodologies:

» US Public Power Electric Utilities With Generation Ownership Exposure, November 2017

» US Municipal Joint Action Agencies, October 2016

» US Municipal Utility Revenue Debt, October 2017

Outlooks:

» Regulated utilities - US 2019 outlook negative amid growing debt and stagnant cash flow

» Unregulated power - US 2019 outlook returns to stable as power prices stabilize, markets begin to balance

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

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