BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of	**UM 2274**
PORTLAND GENERAL ELECTRIC COMPANY	
2023 All-Source Request for Proposals, Request for Partial Waiver of Competitive Bidding Rules.	

Expert Report

on PPA Imputed Debt

of

Michael P. Gorman, CFA

June 21, 2023

BRUBAKER & ASSOCIATES, INC.

Project 11503

My qualifications and experience to offer this expert report are summarized in the attached BAI corporate qualifications profile. This report responds to Portland General Electric Company's ("the Company" or "PGE") proposal to include an imputed debt adjustment cost to purchased power agreements resources in the Scoring methodology (Price scoring) economic comparison of resource options as defined in Appendix N to the 2023 All-Source RFP.

An imputed debt adjustment to the cost of purchased power agreement ("PPA") (generally an imputed debt cost adder) should be excluded from the RFP Scoring Methodology because the PPA imputed debt cost adder creates an economic bias against selecting PPAs as the most economic resource option. As outlined below, PPAs do have contractual financial obligations and do impose financial costs on utilities, including PGE, to balance the leverage risk of resource options including PPAs. But importantly, non-PPA resources also cause financial costs related to the development, operating, decommissioning, and financial risk associated with utility-owned resource options. PGE has not proposed to reflect the added financial costs for the utility-owned resource options in its resource economic evaluation. Therefore, PGE's proposal to add a debt increment adder to the cost of a PPA option is inconsistent and imbalanced. These added financial costs, if accurately measured for all resource options, would largely be offsetting between PPAs and utility-owned resources. Therefore, it is fair and accurate to simply not reflect these external, unknown financial costs in the comparison of resource options.

Additionally, as further detailed in this report, PGE has exaggerated the debt equivalent and has overstated a debt imputation cost for PPAs, if one would be appropriate in isolation of other types of resources, which it is not.

PGE's evidence does not support its proposal to include an imputed debt adder to the cost of a PPA in comparing the cost of various resource options in this RFP. However, if the Commission is interested in further examining PPA debt equivalence and capital structure management issues, PGE could address the issue in PGE's next rate case along with other aspects of its cost of capital and/or cost of service.

UTILITY RESOURCES ADDED COSTS

PGE's Position on Debt Imputation and PPAs

In its scoring the modeling methodology in the 2023 All-Source RFP, PGE describes its fixed cost determination. There, it states for bids that contemplate a PPA, a bid's fixed cost will include (if applicable) all forecasted fixed payments, capacity charges, wheeling charges, integration charges, ancillary services, PGE system upgrade costs, and costs related to imputed debt. PGE goes on to explain the imputed debt-associated costs as related to methodologies produced by Standard & Poor's related to the credit rating of the utility that considers the fixed financial obligation from long-term PPAs which are considered debt equivalents. PGE asserts that S&P's methodology takes the capacity portion of the PPA and calculates the net present value of future payments using a company-specific discount rate and applying an analytically determined risk factor between 25% and 100%. The imputed debt is then added to the Company's total outstanding debt as part of its financial assessment. PGE maintains a comprehensive RFP evaluation. There should be comparability between bids to build owned generation and bids to purchase power from third parties. It maintains that adding an imputed debt equivalent to PPA bids allows for a fair risk assessment of all bids. PGE proposes to calculate an imputed debt adder for a PPA based on the contract length and cost of delivery. It proposes the adders as outlined below:

TABLE 1

Imputed Debt Adder by Contract Length and COD

Contract Length (Years)	Adder (2026 COD)	Adder (2027 COD)
15	2.92%	2.86%
20	3.87%	3.79%
25	4.83%	4.74%
30	5.82%	5.70%

Appendix N – Scoring and Modeling Methodology, 2023 All-Source RFP at page 9, Table 2.

Response

I do not dispute that credit rating agencies will consider a contractual obligation of the utility in an assessment of the overall leverage or financial risk of the utility and that may result in added costs to a utility's cost of service for added PPA leverage risk. However, these added financial costs are not limited to only PPA resource options but rather are also applicable to the added financial cost for utility-owned and utility-developed resource options. PGE has ignored or has understated these financial resource costs for non-PPAs. A balanced review of these added financial risk adjustments shows that the added financial costs for a PPA are similar to the added financial costs for developing and owning utility-owned facilities. Hence, it is not fair, balanced, or accurate to consider only an imputed debt adjustment cost adder for a PPA resource option without also considering the added financial costs for a utility-owned resource option. PGE's comparison creates a clear bias against the cost of PPA resource options and favoritism for utility-owned resources. It is more conservative and more accurate to set the added financial cost issue aside in a resource cost comparison, with the understanding that the utility will need to balance its financial obligations in order to maintain strong credit standing regardless of the resource option selected. Excluding imbalanced and incomplete financial adder costs will allow for the most accurate selection of the best and most economic resource options available to the utility.

PGE's leverage risk is impacted by off-balance sheet debt equivalents associated with PPAs but is also significantly impacted by utility-owned facilities both in terms of construction cash flow constraints on utilities, as well as asset retirement obligations, and employee benefits obligations. Indeed, a review of S&P's leverage adjustments in its credit rating assessment of PGE based on data downloaded in June 2023 is shown below in Table 2.

TABLE 2

Portland General Electric Company

Credit Leverage
(Millions)

Line	Description	2018	2019	2020	2021	2022
		(1)	(2)	(3)	(4)	(5)
	DEBT					
1	Pre-Adjusted Debt	$2,480	$2,597	$3,196	$3,285	$3,646
	Leverage Adjustments					
2	Operating Leases	$209	NA	NA	NA	NA
3	Post-Retirement Benefit Oblg/ Deferred Compensation	$249	$202	$243	$167	$134
4	Accessible Cash & Liquid Investments	($119)	($30)	($257)	($52)	($165)
5	Purchased Power Agreements	$207	$207	$207	$207	NA
6	Asset Retirement Obligations	$102	$112	$160	$141	$125
7	Reported Lease Liabilities	NA	$202	$189	$319	$336
8	Total Adjustments	$648	$694	$542	$783	$429
9	Adjusted Debt	$3,128	$3,291	$3,738	$4,068	$4,075
	EQUITY					
10	Shareholders' Equity, Pre-Adjusted	$2,506	$2,591	$2,613	$2,707	$2,779
11	Total Adjustments	$0	$0	$0	$0	$0
12	**Adjusted Equity**	$2,506	$2,591	$2,613	$2,707	$2,779
13	**Total Adj. Capital**	$5,634	$5,882	$6,351	$6,775	$6,854

Source:
S&P IQ Credit Stats

As shown in the table above, PGE's leverage adjustments in the credit rating review by Standard & Poor's have consistently identified post-retirement benefits and deferred compensation as off-balance sheet equivalents. Asset retirement obligations are also a major factor, as well as PPAs as noted by the Company in its reports. However, employee benefit obligations and asset retirement obligations relate to infrastructure that is owned and developed by the utility. Hence, PPAs have off-balance sheet obligations but then so do utility-owned resources.

Utility Owned Resources Create Ownership and Development Financial Risks

Utility-owned resources that are developed by the utility, impact the utility's cash flows during the resource construction development and create financial risk and costs to the utility. Frequently, utilities are not allowed to recover construction period carrying charges on construction work in progress ("CWIP"), until after the resource is fully developed and placed in-service. During this development period, when the infrastructure investment under development is not included in rates, the utility internal cash flows are generally weak relative to the total debt of the utility, including the debt funding the CWIP. During this development stage, the utility's cash flows coverage of total debt is weak and its credit rating comes under pressure unless the utility mitigates this construction period development financial stress. Reducing the use of utility debt and increasing the use of common equity capital can mitigate the weak cash flow coverage during utility-owned resource construction. The increased use of equity capital that mitigates the utility's resource development stage weak cash flow coverage of total debt is similar to increasing common equity capital to balance total financial risk the PPA added debt equivalent. An increase in common equity capital is a remedy for both utility-owned resource development financial risk, and to balance a PPA debt equivalent financial risk.

In a recent utility industry credit report, Moody's noted the strain on utilities' cash flow created in part by capital spending and utility parent companies' efforts to maintain dividend payments. In a report dated November 10, 2022, "Regulated Electric and Gas Utilities – US 2023 Outlook – Negative on higher natural gas prices, inflation and rising interest rates," Moody's noted the following: Capital spending and dividends will be sustained at a steady clip, which will weigh negatively on the utilities' financial performance. Moody's noted a reduction in the Funds From Operations ("FFO") to Debt ratio caused by the cash obligations of the utility, due to the pressure of financial metrics attributable to higher cost of service, and large capital programs. Moody's opined that credit ratings could improve for utilities if they maintain a targeted level of FFO/Debt ratio due to regulatory support. Moody's specifically noted financial metrics had been under stress due to a change in the Tax Reform Act in 2017 and due to continued high levels of capital expenditures by utilities.

In order to support cash flows coverage of debt during construction, it is not uncommon for a utility to increase its common equity ratio to enhance its internal cash flows coverage of debt to balance out its total leverage during utility asset construction periods, which maintains the utility's financial integrity while it develops major utility-owned resources. Indeed, as shown below in the table, the ratemaking equity ratio used to set rates has been increasing for both electric and gas utilities over the last five years.

This increased equity ratio in part has been used to stabilize financial metrics, including reducing debt so as to enhance FFO/Debt coverages and Debt/EBITDA coverages.

TABLE 3

Trends in State Authorized Common Equity Ratios
(Industry)

		Electric[1]		Natural Gas[1]	
Line	**Year**	**Average**	**Median**	**Average**	**Median**
	(1)	**(2)**	**(3)**	**(4)**	**(5)**
1	2013	50.12%	51.03%	51.16%	50.43%
2	2014	50.28%	50.00%	51.90%	51.99%
3	2015	50.24%	50.48%	49.79%	50.33%
4	2016	49.70%	49.99%	51.85%	51.35%
5	2017	50.02%	49.85%	51.13%	51.76%
6	2018	50.60%	50.23%	52.58%	53.08%
7	2019	51.55%	51.37%	52.72%	52.22%
8	2020	50.94%	51.17%	52.34%	52.00%
9	2021	51.01%	52.00%	51.63%	52.00%
10	2022	51.50%	51.92%	51.84%	52.00%
11	Min	49.70%	49.85%	49.79%	50.33%
12	Max	51.55%	52.00%	52.72%	53.08%
11	Average	50.60%	50.80%	51.69%	51.72%
13	Median	50.44%	50.75%	51.85%	51.99%

Source and Notes:
[1] S&P Global Market Intelligence; data through December 31, 2022.
- Excludes Arkansas, Florida, Indiana and Michigan because they include non-investor capital.

Generally speaking, after the utility increases its equity ratio to support large construction programs, it is my experience that it does not typically reduce its equity ratio after the asset is placed in-service, and the costs of the facility are built into its rate structure. Hence, the increase in equity ratio can frequently be permanent. Stated more directly, because the utilities have financial leverage restrictions already to support utility infrastructure investments, it often can be the case that the mix of debt and equity in the ratemaking capital structure has already adjusted to the point where no additional increase in equity ratio would be necessary to support the off-balance sheet debt equivalent of a PPA.

I also take issue with PGE's assessment of the range of potential risk factors used by Standard & Poor's in assessing the debt equivalent of a PPA. In its analysis, PGE maintains that S&P's methodologies typically use a risk factor in establishing its debt equivalents in the range of 25% to 100%.[1] This representation does not align with S&P's published statements on PPA risk factors. Specifically, S&P states the following:

> Purchased power adjustment
>
> 57. We view long-term purchased power agreements (PPA) as creating fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity. By adjusting financial measures to incorporate PPA fixed obligations, we achieve greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy new load. PPAs do benefit utilities by shifting various risks to the electricity generators, such as construction risk and most of the operating risk. The principal risk borne by a utility that relies on PPAs is recovering the costs of the financial obligation in rates.[2]

The Net Present Values that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%.

> 61. Risk factors based on regulatory or legislative cost recovery typically range between 0% and 50%, but can be as high as 100%. A 100% risk factor would signify that substantially all risk related to contractual obligations rests on the company, with no regulatory or legislative support. A 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers, as when the utility merely acts as a conduit for the delivery of a third party's electricity. . . . We employ a 50% risk factor in cases where regulators use base rates for the recovery of the fixed PPA costs. If a regulator has established a separate adjustment mechanism for recovery of all prudent PPA costs, a risk factor of 25% is employed. In certain jurisdictions, true-up mechanisms are more favorable and frequent than

[1]Appendix N – Scoring and Modeling Methodology, 2023 All Source RFP at page 9.
[2]PGE response to NIPPC Data Request 030, Attachment 030A, *S&P Global RatingsDirect® Criteria/Corporates/Utilities*: "Key Credit Factors For The Regulated Utilities Industry," November 19, 2013 at 14.

> the review of base rates, but still do not amount to pure fuel adjustment clauses.[3]

Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.[4]

While the debt-like equivalent of a PPA, if any, is highly based on the recovery mechanisms provided to the utility to recover the costs of a PPA, it is important to recognize that PGE made no assumptions about how a PPA's costs would be recovered relative to a utility-owned resource. In response to NIPPC Data Request 037, PGE outlined regulatory mechanisms that could be used to recover either a PPA or a Battery Storage Agreement ("BSA"). PGE did indicate that a PPA or BSA's costs could be recovered in PGE's annual power cost update filing, which is a rider with a modified reconciliation feature. If costs are recovered in this vehicle, the debt-like equivalent of a PPA or BSA would be much lower relative to recovering these costs in base rates.

I would also note that in PGE's assessment, a BSA or Storage Capacity Agreement ("SCA") is typically classified as an operating lease, and PGE indicated that an imputed debt adder adjustment to the financial obligations is not applied. (Response to NIPPC Data Request 028(a).) However, this understanding is in conflict with statements made by S&P. Concerning PPA or BSA leasing agreements, S&P states as follows:

> Some PPAs are treated as operating leases for accounting purposes--based on the tenor of the PPA or the residual value of the asset on the PPA's expiration. We accord PPA treatment to those obligations, in lieu of

[3] *Id.*
[4] Standard & Poor's Ratings: "Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements," at 3 (May 7, 2007) (emphasis added).

> lease treatment; rather, the PV of the stream of capacity payments associated with these PPAs <u>is reduced to reflect the applicable risk factor</u>.[5]

<u>Utility-Owned Financial Leverage Cost Adjustments</u>

PGE's proposal to include a PPA leverage cost adjustment to fully account for the cost of PPAs is not balanced by making similar financial leverage cost adjustments to reflect additional leverage balancing costs associated with utility-owned resources.

Utility-owned resources have investment and operating risks that are greater than those inherent in a PPA, in which case the third party assumes the investment and operating risks. For example, a PPA has far less financial risk to the utility compared to utility-owned facilities for the following reasons:

1. A PPA poses little or no cash flow constraints on the utility while the resource is initially being developed. Indeed, PGE acknowledges that under a PPA, it typically would not pay for the capacity and energy from the unit until the unit is actually able to provide capacity and energy to PGE.

2. For a utility self-build project, the utility can go through a period of cash deficiency in the resource development stage if, prior to the unit being placed in service and providing service to customers, the resource cost is not included in tariff rates. This cash stress period during development can also impact the utility's financial leverage and generally could result in the utility increasing the equity ratio of its ratemaking capital structure to accommodate the weak cash flow experienced during the development of a utility-owned resource. The utility cash flow would not be stressed during the development of a PPA resource.

3. The PPA exposes the utility to less asset risk than a utility-owned facility. Specifically, if a PPA failed to operate sufficiently and did not provide capacity and energy, then the utility may not be obligated to pay capacity and energy payments to a third-party supplier under the PPA. The third-party supplier may be liable to PGE for replacement capacity and energy costs if it failed to perform under the PPA. Also, to the extent there is significant prolonged damage to the resources underlying a PPA, PGE may be able to declare the third-party supplier to be in default and can cancel its financial obligations under a PPA. The utility may be largely protected from resource failure under a PPA but not under utility ownership.

4. Under a utility-ownership scenario, the utility has full asset risk for the generating resource, and will still be obligated to make debt service payments for the funding used to develop or acquire the utility-owned resource even if it has a catastrophic

---

[5]PGE response to NIPPC Data Request 030, Attachment 030A, *S&P Global RatingsDirect® Criteria/Corporates/Utilities*: "Key Credit Factors For The Regulated Utilities Industry," November 19, 2013 at 15. Emphasis added

event which removes the resource from public service and precludes full recovery of the utility's costs and outstanding debt from ratepayers.

These resource asset development and operating risks would be considered by credit rating agencies in developing the overall leverage risk and financial risk of PGE in a credit rating review. These risks are unique to utility-owned resources, which PGE would need to manage in balancing a capital structure to maintain its financial integrity and investment grade credit standing. These are all financial costs associated with utility-owned resources which would not be risks or costs incurred under a PPA. Ignoring these utility-owned financial costs to manage development and operating risks as an offset to the PPA debt equivalent renders PGE's proposed cost comparison of the various resources inexact, imbalanced, and biased against PPA bids in the RFP.

In its filing in this case, PGE makes assumptions that effectively assume away the financial risk and potential cost of service impacts from a utility self-build facility. Specifically, as outlined in PGE's response to NIPPC Data Request 031, PGE does confirm that self-build utilities can have cash flow constraints during the development phase of construction, but PGE simply assumes that credit rating agencies will look out over multiple years of construction and post-construction periods in assessing the utility's financial risk. PGE makes no assumption of whether or not it would modify its actual capital structure to mitigate its utility resource development leverage risk by increasing its equity ratio, and reducing its reliance on utility debt, and thus strengthen its revenue and cash flow coverage of utility debt and strengthen its credit rating. By modifying the capital structure by increasing the equity ratio, costs to customers will go up by the development of the utility self-build assets, and the resulting reduction in leverage due to modifying the utility capital structures may be adequate to support the introduction of additional off-balance sheet leverage from a PPA without adding additional costs to the utility. In other words, the modification of the utility's capital structure is already adequate to accommodate both utility self-build construction risk and asset ownership risk, as well as adding off-balance sheet debt leverage obligations associated with the PPAs. No external financial cost adder to a PPA or utility owned resource is necessary.

PGE's proposal to include a PPA debt equivalence adder as part of a PPA's cost in an economic comparison of various resource options should be denied.

Attachment A

Michael P. Gorman Corporate Profile

Michael Gorman

Areas of Expertise

Competitive Procurement
Competitive Energy Procurement
Price Forecasts
Risk Management
Supplier Management

Cost of Service/Rate Design
Alternative/Incentive Regulatory Plans/Mechanisms
Cost of Service
Electric Fuel and Gas Cost Reviews and Rates
Marginal Cost Analysis
Nuclear Decommissioning Costs
Performance Based Rates
Prudence and Used/Useful Evaluation
Rate Design and Tariff Analysis
Storage Cost/Necessity

Financial
Asset /Enterprise Valuation
Cost of Capital
Depreciation Studies
Financial Integrity
Merger Evaluations (Benefit/Costs)
Revenue Requirement Issues

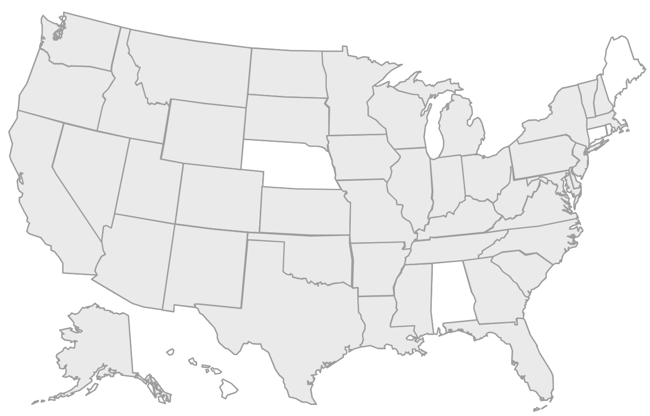
Special Projects
Site Selection and Evaluation
Training Seminars

Mr. Gorman is a Managing Principal at BAI. He received Degrees of Bachelor of Science in Electrical Engineering from Southern Illinois University at Carbondale and Master of Business Administration from the University of Illinois at Springfield. Mr. Gorman has also done extensive graduate studies in Financial Economics. He earned the designation Chartered Financial Analyst (CFA) from the CFA Institute.

Mr. Gorman has been in the consulting practice since 1990, and in the energy business since 1983. Mr. Gorman was employed by the Illinois Commerce Commission and held positions including Director of the Financial Analysis Department, Senior Analyst, Planning Analyst and Utility Engineer. Mr. Gorman was also employed by Merrill Lynch as a Financial Consultant. In this position, he consulted on cash management and investment strategies.

His responsibilities at BAI include project management, cost of capital studies, depreciation studies, financial integrity studies, system resource planning studies, alternative regulation plan/mechanisms, cost of service, rate design, production cost evaluations, commodity risk management, commodity procurement management, competitive supplier management and counterparty credit risk.

Project Work



Other Project Work

- Alberta
- Board of Public Utilities of Kansas City, Kansas
- City of Austin Electric Utility Council
- Federal Energy Regulatory Commission (FERC)
- LaGrange, Georgia / Municipal Electric Authority of Georgia
- Newfoundland
- Nova Scotia
- Salt River Project

Attachment B

PGE Responses to NIPPC Data Requests

June 19, 2023

To: Irion Sanger
Northwest and Intermountain Power Producers Coalition

From: Erin Apperson
Assistant General Counsel III

Portland General Electric Company
UM 2274
PGE Response to NIPPC Data Request 028
Dated June 5, 2023

<u>Request:</u>

Please reference PGE's 2023 RFP, Appendix N where PGE states "Table 2 below provides the calculated imputed debt adder for [power purchase agreements ('PPAs')] by contract length and COD."

a. Does the imputed debt adder apply to battery storage agreements ("BSAs")?
b. Is the notion of including an imputed debt bid adder an attempt to estimate the cost to PGE's customers for a PPA or BSA resource options? Please explain your answer.
c. Does PGE's proposed PPA or BSA imputed debt bid adder attempt to represent the additional utility cost of selecting a PPA or BSA resource option? Please explain your answer.
d. Is PGE proposing to include additional utility costs for self-build benchmarks or Build Transfer Agreement ("BTA") options in selecting resource options? Please explain your answer.
e. Please explain how PGE's calculation of imputed debt differs from Idaho Power Company's calculation of its proposed imputed debt adder in Idaho Power Company's 2026 RFP in OPUC Docket No. UM 2255.

<u>Response:</u>

a. Battery storage agreements ("BSA") or storage capacity agreements ("SCA") are classified as operating leases on the balance sheet and therefore the imputed debt adder is not applied.
b. The imputed debt adder reflects the theoretical impact of adding an incremental debt equivalency to the credit rating agency ratios, which directly impact PGE's credit rating.
c. See response to subpart (b).
d. PGE will include a transferability discount, explained in greater detail in Appendix N of the RFP Draft filing, to all utility ownership structures which include either the investment tax credit and/or the production tax credit.
e. PGE objects to this request as not reasonably calculated to elicit or lead to relevant evidence in this proceeding. In particular, this request seeks information about Idaho Power

Company's proposal in a separate proceeding. Additionally, this request seeks new analysis which the company is not required to perform.

June 19, 2023

To: Irion Sanger
Northwest and Intermountain Power Producers Coalition

From: Erin Apperson
Assistant General Counsel III

Portland General Electric Company
UM 2274
PGE Response to NIPPC Data Request 030
Dated June 5, 2023

Request:

Please provide copies of all correspondence between PGE and credit rating agencies concerning its methodology of establishing debt equivalents costs for PPA or BSA resource contracts, and describe the impact on PGE's credit rating due to PPA or BSA debt equivalents, and options to PGE to manage its financial leverage and cost of capital for resource options including PPAs, BSAs, self-build benchmarks, and BTAs.

Response:

PGE objects to this request on the basis that it is overly broad and seeks information not relevant to this proceeding. Without waiving its objection, PGE responds as follows:

PGE does not have any substantive relevant correspondence to the request. PGE follows the established S&P methodology of determining debt equivalent costs for PPA resource contracts. Attachment 030-A provides S&P's methodology.

RatingsDirect®

Criteria | Corporates | Utilities:

Key Credit Factors For The Regulated Utilities Industry

Primary Credit Analysts:
Richard P Creed, Melbourne (61) 3-9631-2045; richard.creed@standardandpoors.com
Vittoria Ferraris, Milan (39) 02-72111-207; vittoria.ferraris@standardandpoors.com
Sergio Fuentes, Buenos Aires (54) 114-891-2131; sergio.fuentes@standardandpoors.com
Gabe Grosberg, New York (1) 212-438-6043; gabe.grosberg@standardandpoors.com
Parvathy Iyer, Melbourne (61) 3-9631-2034; parvathy.iyer@standardandpoors.com
Gerrit W Jepsen, CFA, New York (1) 212-438-2529; gerrit.jepsen@standardandpoors.com
Andreas Kindahl, Stockholm (46) 8-440-5907; andreas.kindahl@standardandpoors.com
John D Lindstrom, Stockholm (46) 8-440-5922; john.lindstrom@standardandpoors.com
Nicole D Martin, Toronto (1) 416-507-2560; nicole.martin@standardandpoors.com
Sherman A Myers, CPA, New York (1) 212-438-4229; sherman.myers@standardandpoors.com
Dimitri Nikas, New York (1) 212-438-7807; dimitri.nikas@standardandpoors.com
Ana M Olaya-Rotonti, New York (1) 212-438-8668; ana.olaya-rotonti@standardandpoors.com
Hiroki Shibata, Tokyo (81) 3-4550-8437; hiroki.shibata@standardandpoors.com
Todd A Shipman, CFA, New York (1) 212-438-7676; todd.shipman@standardandpoors.com
Alf Stenqvist, Stockholm (46) 8-440-5925; alf.stenqvist@standardandpoors.com
Tania Tsoneva, CFA, London (44) 20-7176-3489; tania.tsoneva@standardandpoors.com
Mark J Davidson, London (44) 20-7176-6306; mark.j.davidson@standardandpoors.com

Criteria Officer:
Mark Puccia, New York (1) 212-438-7233; mark.puccia@standardandpoors.com

Table Of Contents

Table Of Contents (cont.)

Key Credit Factors For The Regulated Utilities Industry

*(**Editor's Note:** We originally published this criteria article on Nov. 19, 2013. We're republishing it following our criteria review completed on June 17, 2014. We also updated the contact list on Jan. 30, 2015. This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," published Nov. 26, 2008, "Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.)*

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

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

SCOPE OF THE CRITERIA

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

SUMMARY OF THE CRITERIA

4. Standard & Poor's is updating its criteria for analyzing regulated utilities, applying its corporate criteria. The criteria for evaluating the competitive position of regulated utilities amend and partially supersede the "Competitive Position"

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

IMPACT ON OUTSTANDING RATINGS

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

EFFECTIVE DATE AND TRANSITION

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

METHODOLOGY

Part I--Business Risk Analysis

Industry risk

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

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

Cyclicality

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

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

Competitive risk and growth

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

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

Effectiveness of barriers to entry--low risk

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

Level and trend of industry profit margins--low risk

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

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

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

Risk in industry growth trends--low risk

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

B. Country risk

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

C. Competitive position

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

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

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

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

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

Assessing regulatory advantage

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

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

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

24. Regulatory stability:

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

25. Tariff-setting procedures and design:

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

26. Financial stability:

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

27. Regulatory independence and insulation:

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

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

Table 1

Preliminary Regulatory Advantage Assessment

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

Table 1

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

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

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

Table 2

Determining The Final Regulatory Advantage Assessment

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

Scale, scope, and diversity

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

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

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

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

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

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

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

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

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

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

Operating efficiency

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

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

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

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

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

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

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

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

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

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

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

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

operating efficiency is generally otherwise considered adequate.

Profitability

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

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

Level of profitability

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

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

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

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

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

Volatility of profitability

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

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

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

Part II--Financial Risk Analysis

D. Accounting

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

Accounting characteristics

55. Some important accounting practices for utilities include:

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

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

Purchased power adjustment

57. We view long-term purchased power agreements (PPA) as creating fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity. By adjusting financial measures to incorporate PPA fixed obligations, we achieve greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy new load. PPAs do benefit utilities by shifting various risks to the electricity generators, such as construction risk and most of the operating risk. The principal risk borne by a utility that relies on PPAs is recovering the costs of the financial obligation in rates.

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

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

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

61. Risk factors based on regulatory or legislative cost recovery typically range between 0% and 50%, but can be as high as 100%. A 100% risk factor would signify that substantially all risk related to contractual obligations rests on the company, with no regulatory or legislative support. A 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers, as when the utility merely acts as a conduit for the delivery of a third party's electricity. These utilities are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties that act as intermediaries between retail customers and electricity suppliers. We employ a 50% risk factor in cases where regulators use base rates for the recovery of the fixed PPA costs. If a regulator has established a separate adjustment mechanism for recovery of all prudent PPA costs, a risk factor of 25% is employed. In certain jurisdictions, true-up mechanisms are more favorable and frequent than the review of base rates, but still do not amount to pure fuel adjustment clauses. Such mechanisms may be triggered by financial thresholds or passage of prescribed periods of time. In these instances, a risk factor between 25% and 50% is employed. Specialized, legislatively created cost-recovery mechanisms may lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative

guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors. We also exclude short-term PPAs where they serve merely as gap fillers, pending either the construction of new capacity or the execution of long-term PPAs.

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

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

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

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

66. Adjustment procedures:

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

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

imputed debt (or average PPA imputed debt, if there is fluctuation of the level), and is added to interest expense.

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

Natural gas inventory adjustment

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

68. Adjustment procedures:

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

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

Securitized debt adjustment

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

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

70. Full cost recovery is in most instances mandated by statute. Examples of securitized costs include "stranded costs"

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

71. Adjustment procedures:

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

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

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

Infrastructure renewals expenditure

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

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

from FFO.

74. Adjustment procedures:

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

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

E. Cash flow/leverage analysis

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

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

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

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

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

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

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

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

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

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

Part III--Rating Modifiers

F. Diversification/portfolio effect

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

G. Capital structure

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

H. Liquidity

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

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

I. Financial policy

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

J. Management and governance

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

K. Comparable ratings analysis

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

Appendix--Frequently Asked Questions

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

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

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

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

What is your definition of regulatory jurisdiction?

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

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

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

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

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

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

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

RELATED CRITERIA AND RESEARCH

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

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

(And watch the related CreditMatters TV segment titled, "Standard & Poor's Highlights The Key Credit Factors For Rating Regulated Utilities," dated Nov. 21, 2013.)

June 19, 2023

To: Irion Sanger
Northwest and Intermountain Power Producers Coalition

From: Erin Apperson
Assistant General Counsel III

Portland General Electric Company
UM 2274
PGE Response to NIPPC Data Request 031
Dated June 5, 2023

<u>Request:</u>

Concerning utility-owned resources and the impact on PGE's credit rating, please answer the following:

a. Confirm or deny that constructing a self-build benchmark or acquiring a BTA resources option can result in negative impacts on utility internal cash flows and cash flows from operations during the construction period of a utility-owned generation resource if the development costs are not recovered from customers until the resource is placed in-service. If deny, please explain your answer.

b. Confirm or deny that PGE will have to manage its capital structure and financial strength during a construction period for a self-build benchmark, or at the close of construction for a BTA, to balance out the cash needed for major construction expenditures, and that needed to support the utility bond rating to support access to external capital. If deny, please explain your answer.

c. Please identify the options available to PGE to manage its internal cash flow and funds from operations in a manner that is adequate to support its current investment grade bond rating, during the development of a self-build benchmark and BTA generation resources.

<u>Response:</u>

PGE understands the terms "internal cash flows" and "cash flows from operations" to be interchangeable.

During the construction period, project financing temporarily impacts cash from operations and cash from financing which puts temporary pressure on PGE's credit metrics. When doing their assessments, credit rating agencies generally look over a multi-year period and not at point-in-time performance. While financing strength and metrics are an important piece of the credit rating methodology, the rating agencies also look to the regulatory framework. A stronger rating is given to those utilities with supportive regulatory environments that provide predictable and timely recovery of operating and capital costs. This is notably different than with a PPA where the pressure on PGE’s credit metrics is permanent and remains as additional debt through the life of the agreement.

June 19, 2023

To: Irion Sanger
Northwest and Intermountain Power Producers Coalition

From: Erin Apperson
Assistant General Counsel III

Portland General Electric Company
UM 2274
PGE Response to NIPPC Data Request 037
Dated June 5, 2023

Request:

Please describe the regulatory mechanisms under which PGE would recover the costs of a utility-owned facility versus the costs of a PPA or BSA. Please state whether or not the regulatory mechanisms are adjusted within the utility rate cases, or outside rider surcharge mechanism, and state whether or not the regulatory mechanism has a reconciliation feature.

Response:

PGE objects to this request on the basis that it is vague and overly broad. Notwithstanding its objection, PGE responds as follows:

Some potential regulatory mechanisms that could be used are very similar for utility-owned facilities versus a PPA or BSA. It is possible, depending on the type and timing of resource, that any of these products could be included within:

1. A general rate case filing, which is a rate case and does not include a reconciliation.
2. A renewable automatic adjustment clause filing (PGE Schedule 122), which is a rider and may include a reconciliation.
3. A request for deferred accounting and subsequent amortization, in which the amortization may be a rider and may include a reconciliation feature.

Additionally, a PPA or BSA can typically be included within PGE's annual power cost update filing (PGE Schedule 125), which is a rider during non-general rate case years and has a modified reconciliation feature subject to the requirements of PGE Schedule 126 (PGE's power cost adjustment mechanism).