VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Bruce Sailers, Director Jurisdictional Rate Administration, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Bruce L. Sailers
Bruce Sailers Affiant

Subscribed and sworn to before me by Bruce Sailers on this 1st day of March, 2023.

Emilie Sunderman
NOTARY PUBLIC

My Commission Expires: July 8, 2027

NOTARY PUBLIC STATE OF OHIO

EMILIE SUNDERMAN
Notary Public
State of Ohio
My Comm. Expires
July 8, 2027

VERIFICATION

STATE OF INDIANA)
) **SS:**
COUNTY OF)

The undersigned, Cormack C. Gordon, Director Transportation Electrification, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Cormack C. Gordon Affiant

Subscribed and sworn to before me by Cormack C. Gordon on this 23 day of February, 2023.

NOTARY PUBLIC

My Commission Expires: 3/26/27

KARA LYNNE LUKEHART
NOTARY PUBLIC
LINCOLN COUNTY, NC
MY COMMISSION EXPIRES 3/26/27

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Huyen C. Dang, Director of Accounting, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

____
Huyen C. Dang Affiant

Subscribed and sworn to before me by Huyen C. Dang on this 2 day of March, 2023.

VIRGINIA M. ADAMS
My Comm. Expires
NOTARY
PUBLIC
October 2, 2026
MECKLENBURG COUNTY, NC

Virginia M. Adams
NOTARY PUBLIC

My Commission Expires: 10/2/26

VERIFICATION

STATE OF NORTH CAROLINA)
) SS:
COUNTY OF MECKLENBURH)

The undersigned, Jacob Colley, Director Customer Services Strategy, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Jacob S. Colley
Jacob Colley Affiant

Subscribed and sworn to before me by Jacob Colley on this 24th day of FEBRUARY, 2023.

Annette Djohou
NOTARY PUBLIC
Mecklenburg County, NC

Annette
NOTARY PUBLIC

My Commission Expires: 01/02/2024

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, James E. Ziolkowski, Director, Rates & Regulatory Planning, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

James E. Ziolkowski Affiant

Subscribed and sworn to before me by James E. Ziolkowski on this 1st day of March, 2023.

NOTARY PUBLIC

My Commission Expires: July 8, 2027

NOTARY PUBLIC STATE OF OHIO

EMILIE SUNDERMAN
Notary Public
State of Ohio
My Comm. Expires
July 8, 2027

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	**SS:**
COUNTY OF MECKLENBURG	)	

The undersigned, John Swez, Managing Director Trading & Dispatch, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief

John Swez Affiant

Subscribed and sworn to before me by John Swez on this 21 day of February 2023.

NOTARY PUBLIC

My Commission Expires:

SHAMELL M WILSON
My Comm. Expires
NOTARY PUBLIC
July 06, 2026
MECKLENBURG COUNTY, NC

VERIFICATION

COMMONWEALTH OF MASSACHUSETTS	)	
	)	**SS:**
COUNTY OF MIDDLESEX	)	

The undersigned, Joshua C. Nowak, Vice President, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Joshua C. Nowak Affiant

Subscribed and sworn to before me by Joshua C. Nowak on this 24th day of February, 2023.

NOTARY PUBLIC

My Commission Expires: 11/27/26

REGINA A. KOLB
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires On
November 27, 2026

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Lisa Steinkuhl, Director Rates & Regulatory Planning, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Lisa D Steinkuhl
Lisa Steinkuhl Affiant

Subscribed and sworn to before me by Lisa Steinkuhl on this 28th day of February, 2023.

NOTARY PUBLIC

My Commission Expires: July 8, 2027

NOTARY PUBLIC STATE OF OHIO

EMILIE SUNDERMAN
Notary Public
State of Ohio
My Comm. Expires
July 8, 2027

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, J. Michael Geers, Manager Environmental Services, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

J Michael Geers

J. Michael Geers Affiant

Subscribed and sworn to before me by J. Michael Geers on this 1st day of March, 2023.

Emilie Sunderman

NOTARY PUBLIC

My Commission Expires: July 8, 2027

NOTARY PUBLIC STATE OF OHIO

EMILIE SUNDERMAN
Notary Public
State of Ohio
My Comm. Expires
July 8, 2027

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Paul Halstead, Director Jurisdictional Rate Administration, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief

Paul Halstead Affiant

Subscribed and sworn to before me by Paul Halstead on this 23 day of February 2023.

LAUREN A PADILLA
NOTARY
PUBLIC
CABARRUS COUNTY, NC

NOTARY PUBLIC

My Commission Expires: 3/3/27

KyPSC Case No. 2022-00372
TABLE OF CONTENTS

PUBLIC STAFF-DR-03-001

REQUEST:

Refer to Duke Kentucky's current tariff on file with the Commission, Sheet No. 74, Rider AMO, Advanced Meter Opt-Out (AMO) – Residential.

a. Provide the number of customers currently participating in Rider AMO.

b. Provide detailed cost support for the $100 one-time fee and the $25 recurring monthly fee.

c. If labor is included in the cost support above, explain whether Duke Kentucky used contract labor, Duke Kentucky employees, or a combination of both, to perform the services.

d. For the last five calendar years, provide the amount of Rider AMO fees billed by month.

e. Explain whether the expenses and revenues from Rider AMO were included in Duke Kentucky's calculation of its revenue requirement in this proceeding. If so, identify how they were included in the revenue requirement calculation.

RESPONSE:

<u>CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment 1 only)</u>

a. As of 2/1/2023, two hundred seventy-five (275) customers participate in Rider AMO.

b. The costs referenced were approved by the Commission as reasonable in the Commission's order on May 25, 2017 in Case No. 2016-00152. The Commission approved these costs as part of settlement in the referenced case. The charges have not been changed and they were supported in CONFIDENTIAL STAFF-POST HEARING-DR-01-007 and STAFF-POST HEARING-DR-01-008. The referenced responses are attached as STAFF-DR-03-001 Confidential Attachment 1 and STAFF-DR-03-001 Attachment 2.

c. Rider AMO participant meters could be read by Company employees or contractors.

d. Please see STAFF-DR-03-001 Attachment 3.

e. In Schedule M, Rider AMO revenue collection is included under the Other Miscellaneous Revenue section as part of the Other Miscellaneous line item. This revenue acts as an offset to the revenue requirements collected through base rate charges.

PERSON RESPONSIBLE: Bruce L. Sailers

CONFIDENTIAL PROPRIETARY TRADE SECRET

STAFF-DR-03-001
CONFIDENTIAL ATTACHMENT 1

FILED UNDER SEAL

Duke Energy Kentucky
Case No. 2016-00152
STAFF'S POST-HEARING First Set Data Requests
Date Received: December 13, 2016

STAFF-POST HEARING-DR-01-008

REQUEST:

Refer to PAL-SET-1, page 1 of 2. Provide the one-time opt-out cost for an electric-only customer.

RESPONSE:

The current electric opt-out calculation spreads the costs over the total residential electric customer base (electric only and combination electric/gas). Therefore, if the calculation of the opt-out for electric only residential customers is dissected from the total number of residential electric customer base, the costs for combination customers would increase.

If electric-only customers did not share in the one-time costs associated with gas service, the electric-only customers' one-time costs would be equal to $125.26, which is less than the total on PAL-SET-1, but still more than the proposed $100 tariffed rate.

One-time Costs to Establish AMO	
Customer Service @ 3 mins/customer	$1.37
Metering Services Work Order Mgmt @ 5 mins/customer	$4.63
Manual Meter Reading Route Analysis @ 20 mins/customer	$21.57
Senior Meter Tester to disable meter radios @ 30 mins/customer	$40.47
Field service personnel to exchange meter @ 45 mins/customer	$54.26
Vehicle to exchange meter @ 45 mins/customer	$2.96
Gas Operations to remove AMI module from gas meter @ 45 mins/customer	$0.00

Vehicle to remove gas AMI module @ 45 mins/customer	$0.00
Total One-Time Costs	**$125.26**

As previously stated, the one-time cost estimate in PAL-SET-1 reflects an allocation of gas-related costs across all residential electric opt-out customers. If residential electric opt-out customers with gas service (combo customers) paid all the one-time costs associated with gas service, the combo customers' one-time costs would be equal to $185.74, which exceeds the total on PAL-SET-1.

One-time Costs to Establish AMO	
Customer Service @ 3 mins/customer	$1.37
Metering Services Work Order Mgmt @ 5 mins/customer	$4.63
Manual Meter Reading Route Analysis @ 20 mins/customer	$21.57
Senior Meter Tester to disable meter radios @ 30 mins/customer	$40.47
Field service personnel to exchange meter @ 45 mins/customer	$54.26
Vehicle to exchange meter @ 45 mins/customer	$2.96
Gas Operations to remove AMI module from gas meter @ 45 mins/customer	$57.28
Vehicle to remove gas AMI module @ 45 mins/customer	$3.20
Total One-Time Costs	**$185.74**

PERSON RESPONSIBLE: Peggy Laub

Duke Energy Kentucky Inc.
Case No. 2022-00372
Non-Standard Meter Option Fees

	2018	2019	2020	2021	2022
January	$ 675	$ 12,450	$ 9,350	$ 7,775	$ 7,250
February	$ 1,000	$ 12,900	$ 9,125	$ 7,600	$ 6,950
March	$ 1,750	$ 12,450	$ 7,550	$ 7,800	$ 7,025
April	$ 2,075	$ 12,050	$ 5,650	$ 7,650	$ 4,315
May	$ 2,775	$ 11,725	$ 5,775	$ 7,675	$ 7,047
June	$ 3,975	$ 11,050	$ 5,850	$ 7,550	$ 5,929
July	$ 6,275	$ 10,675	$ 5,700	$ 7,550	$ 5,805
August	$ 7,425	$ 10,250	$ 7,825	$ 7,325	$ 6,385
September	$ 9,100	$ 9,875	$ 8,625	$ 7,225	$ 6,694
October	$ 10,850	$ 9,700	$ 8,575	$ 7,200	$ 6,523
November	$ 11,775	$ 9,600	$ 8,350	$ 7,300	$ 5,839
December	$ 11,650	$ 9,450	$ 8,000	$ 7,175	$ 5,736
Total	$ 69,325	$ 132,175	$ 90,375	$ 89,825	$ 75,499

Duke Energy Kentucky
Case No. 2022-00372
STAFF Third Set Data Requests
Date Received: February 17, 2023

STAFF-DR-03-002

REQUEST:

Refer to the Direct Testimony of Amy Spiller (Spiller Direct Testimony), page 5, line 15, through page 6, line 5, which lists Duke Kentucky's local electric operations. Also refer to Duke Kentucky's response to the Attorney General's First Request for Information, Item 11(b). Explain whether a customer has the option to speak with Duke Kentucky representatives in person regarding their account. If so, list the location of the office(s) where this is available.

RESPONSE:

Duke Energy Kentucky continues to enhance its digital and voice offerings for customers and these diverse and dynamic channels for customers to engage with the Company are described in the Direct Testimonies of Amy Spiller and Jacob Colley and in response to STAFF-DR-03-003. We also have a dedicated team serving assistance agencies to better support customers seeking financial assistance. If a customer feels that their needs have not been addressed via these channels, a dedicated Consumer Affairs organization is available to address any escalated concerns or complaints.

In addition to its off-site call centers across the Duke Energy Corporate footprint, Duke Energy Kentucky/Ohio headquarters, located at 139 East Fourth Street Cincinnati, Ohio includes customer care representatives who can be available to meet in person with customers. In the interests of protecting and providing for security of employees and in recognition of more recent health and safety protocols due to COVID-19, and in recognition of current hybrid (onsite/remote) employee staffing, customers must request at the front security desk to speak to someone in person. A representative will come down to meet with the customer in the lobby in view of security, where there are tables and chairs available. In addition, small glass conference rooms are available that are located in front of security in the event the customer wishes for more privacy. For safety and security reasons, cash payments cannot be accepted in person, but the agent will work with the customer for convenience payment processing, which may include electronic or identifying the closest most convenience agent for the customer to make an in-person payment.

PERSON RESPONSIBLE: Amy B. Spiller

STAFF-DR-03-003

REQUEST:

Provide the number for each of the following that are available to Duke Kentucky's customers.

a. Offices.

b. Service centers.

c. Mobile payment centers.

RESPONSE:

As described in the Direct Testimonies of Amy Spiller and Jacob Colley, the company provides many diverse and dynamic channels for customers to engage with the Company. These programs include:

- approximately 300 live residential and business customer care specialists who handle inbound and outbound calls;
- enhanced Intelligent Voice Response (IVR) system allows customers many self-serve options such as requesting payment arrangements and reporting power outages, update account information, enroll/withdraw from Budget Billing;
- enhanced web functionality for online services such as a planned vegetation management map, a feature alerting customers to estimated call wait times, the ability for customers to start and stop service online, a digital, self-enrollment option for payment arrangements, and resources directing them to agency assistance support when needed;

- Business Service Center (BSC) focused on providing a more tailored service model customized by business segment for our Small/ Medium business customers;
- 70 pay agent locations for customers to utilize to pay monthly bills; and
- the social media customer care program which operates Monday through Friday to assist customers on the Duke Energy enterprise social media channels which consist of Facebook, Twitter, LinkedIn, and Instagram.

Duke Energy Kentucky transitioned from offering walk-in pay locations on September 10, 2009, as was reported to the Commission by letter dated August 26, 2009. The Company reported on this as part of its annual merger reporting updates in Case No. 2005-00228, for calendar years 2010, 2011, and 2012, which are on file with the Commission. Additionally, as the Company explained in its Exhibit L, pg. 49, Direct Testimony of Julie Janson, President of Duke Energy Kentucky in Case No. 2011-00124, "Duke Energy Kentucky closed its walk-in customer service office in 2009 as part of its implementation of best practices and in consideration of employee safety. To mitigate the impact of the closure on customer service, the Company increased the number of local pay stations throughout its service territory and implemented new electronic bill payment alternatives for its customers…"

a.-b. Please see the Direct Testimony of Amy B. Spiller, pg. 5, for a description of Duke Energy Kentucky's Electric operations, including its facilities used to provide service to customers. These include as follows:

- Cincinnati, Ohio – the headquarters for Duke Energy Kentucky
- Rabbit Hash, Kentucky – the East Bend Generating Station
- Trenton, Ohio – the Woodsdale Generating Station

- Erlanger, Kentucky – Duke Energy Kentucky's construction and maintenance facility
- Covington, Kentucky – Duke Energy Kentucky's meter reading facility
- Harrison, Ohio – Duke Energy Kentucky and Ohio's Electric System Operations Facility

The Company uses its Erlanger construction and maintenance facility as its primary Kentucky location for customers to review tariffs and filings.

c. Please see the Direct Testimony of Amy Spiller for a description of the Company's pay-agent networks. Presently, there are currently seventy (70) locations in the Duke Energy Kentucky service area where customers can make cash, check, or money order payments. These locations are found in establishments where customers typically conduct other business, such as grocery stores, pharmacies, convenience stores, and larger retailers.

PERSON RESPONSIBLE: Amy B. Spiller

STAFF-DR-03-004

REQUEST:

Refer to the Direct Testimony of Bruce L. Sailers (Sailers Direct Testimony), page 26, lines 14–15, in which it is stated that the proposed changes to Rider DIR will improve Duke Kentucky's competitiveness in the region. Explain whether any potential customers have expressed reservations about locating in Duke Kentucky's service territory due to the current terms of Rider DIR not being competitive with offerings of other utilities in the region.

RESPONSE:

No customers have expressed reservations to date. However, Duke Energy Indiana and Duke Energy Ohio have approved economic development tariffs similar to the proposed tariff for the Company. The Company does not always know why a customer ultimately decides to locate in another service area. But the proposed Rider DIR will level the playing field with the other utilities referenced above.

PERSON RESPONSIBLE: Bruce L. Sailers

Duke Energy Kentucky
Case No. 2022-00372
STAFF Third Set Data Requests
Date Received: February 17, 2023

STAFF-DR-03-005

REQUEST:

Refer to the Direct Testimony of Joshua C. Nowak (Nowak Direct Testimony), page 26, line 14. Explain the rationale for limiting the selection of proxy group companies to those owning regulated generation assets. Include in the response why electric utilities not owning regulated generation should be excluded from the proxy group when these companies are implicitly included in the derivation of the risk premium regression analysis.

RESPONSE:

It is generally recognized that utilities with generation assets, like Duke Energy Kentucky, face greater risk than utilities with only transmission and distributions assets. As demonstrated on page 23 of STAFF-DR-03-005 Attachment, Moody's has commented on the additional risk associated with generation assets as follows:

> "Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays."[1]

The risks associated with the electric generation segment of the business are attributable to project development, early obsolescence and technology changes, shifts in environmental laws and regulations, fuel availability and contracting, operations, and the potential for

[1] Moody's Investors Service, "Rating Methodology; Regulated Electric and Gas Utilities," originally published December 23, 2013, updated June 23, 2017, at 23.

regulatory cost disallowances associated with any of these factors. Given the incremental risk associated with generation assets, a higher return is typically required for a vertically integrated utility as compared to transmission and distribution-only utilities. Consistent with this point, based on electric rate case decisions published by Regulatory Research Associates, since 2017 the average authorized ROE for vertically integrated electric utilities has been more than 40 basis points higher than ROEs authorized for transmission and distribution-only utilities. Therefore, to select a proxy group with a similar risk profile to Duke Energy Kentucky, a vertically integrated utility, it is appropriate to include companies that own generation assets.

With regard to the risk premium analysis, the question is incorrect that electric utilities not owning regulated generation "are implicitly included in the derivation of the risk premium regression analysis." As described in Direct Testimony of Joshua C. Nowak, page 39, lines 10-12, "Data regarding allowed ROEs were derived from vertically integrated electric utility company rate cases from January 1, 1992 through October 31, 2022, as reported by Regulatory Research Associates." Since the dataset is limited to vertically integrated utilities, electric utilities not owning regulated generation are excluded in the derivation of the risk premium regression analysis.

PERSON RESPONSIBLE: Joshua C. Nowak

JUNE 23, 2017

INFRASTRUCTURE

MOODY'S INVESTORS SERVICE

RATING METHODOLOGY

Regulated Electric and Gas Utilities

Table of Contents:

Analyst Contacts:

NEW YORK +1.212.553.1653

Michael G. Haggarty +1.212.553.7172
Associate Managing Director
michael.haggarty@moodys.com

Jim Hempstead +1.212.553.4318
Managing Director – Utilities
james.hempstead@moodys.com

Walter Winrow +1.212.553.7943
Managing Director - Global Project and Infrastructure Finance
walter.winrow@moodys.com

Jeffrey Cassella +1.212.553.1665
Vice President - Senior Analyst
jeffrey.cassella@moodys.com

Natividad Martel +1.212.553.4561
Vice President - Senior Analyst
natividad.martel@moodys.com

» *contacts continued on the last page*

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

Summary

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

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

THIS METHODOLOGY WAS UPDATED ON THE DATES LISTED AS NOTED: ON SEPTEMBER 10, 2020, WE REMOVED POINT-IN-TIME REFERENCES AND ALSO MADE MINOR FORMATTING CHANGES; ON NOVEMBER 4, 2019, WE UPDATED SOME OUTDATED REFERENCES AND ALSO MADE MINOR FORMATTING CHANGES; ON FEBRUARY 22, 2019, WE AMENDED A REFERENCE TO A METHODOLOGY IN APPENDIX E AND REMOVED OUTDATED TEXT; ON AUGUST 2, 2018, WE MADE MINOR FORMATTING CHANGES THROUGHOUT THE METHODOLOGY; ON FEBRUARY 15, 2018, WE CORRECTED THE FORMATTING OF THE FACTOR 4: FINANCIAL STRENGTH TABLE ON PAGE 34; AND ON SEPTEMBER 27, 2017, WE REMOVED A DUPLICATE FOOTNOTE THAT WAS PLACED IN THE MIDDLE OF THE TEXT ON PAGE 7.

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

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

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

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

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

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A discussion of the scorecard factors

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

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

This methodology describes the analytical framework used in determining credit ratings. In some instances, our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities.[2]

[2] A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section.

About the Rated Universe

This methodology applies to rate-regulated[3] electric and gas utilities that are not Networks[4]. Regulated electric and gas utilities are companies whose predominant[5] business is the sale of electricity and/or gas or related services under a rate-regulated framework, in most cases to retail customers. Also included under this methodology are rate-regulated utilities that own generating assets as any material part of their business, utilities whose charges or bills to customers include a meaningful component related to the electric or gas commodity, utilities whose rates are regulated at a sub-sovereign level (e.g. by provinces, states or municipalities), and companies providing an independent system operator function to an electric grid. Companies rated under this methodology are primarily rate-regulated monopolies or, in certain circumstances, companies that may not be outright monopolies but where government regulation effectively sets prices and limits competition.

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

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

This methodology pertains to regulated electric and gas utilities and excludes the following types of issuers, which are covered by separate rating methodologies: regulated networks, unregulated utilities and power companies, public power utilities, municipal joint action agencies, electric cooperatives, regulated water companies and natural gas pipelines.[6]

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

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

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

6 A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section.

About this Rating Methodology

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

1. Identification and Discussion of the Scorecard Factors

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

Factor / Sub-Factor Weighting - Regulated Utilities

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

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

2. Measurement or Estimation of Factors in the Scorecard

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

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) in the scorecard. However, the factors in the scorecard can be assessed using various time

[7] For more information, see our cross-sector methodology that describes our standard adjustments in the analysis of non-financial corporations. A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section.

periods. For example, rating committees may find it analytically useful to examine both historic and expected future performance for periods of several years or more, or for individual twelve-month periods.

3. Mapping Scorecard Factors to the Rating Categories

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

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

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

5. Determining the Overall Scorecard-Indicated Outcome[8]

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

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

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

Scorecard-Indicated Outcome

Scorecard-Indicated Outcome	Aggregate Weighted Total Factor Score
Aaa	x < 1.5
Aa1	1.5 ≤ x < 2.5
Aa2	2.5 ≤ x < 3.5
Aa3	3.5 ≤ x < 4.5
A1	4.5 ≤ x < 5.5
A2	5.5 ≤ x < 6.5
A3	6.5 ≤ x < 7.5
Baa1	7.5 ≤ x < 8.5
Baa2	8.5 ≤ x < 9.5
Baa3	9.5 ≤ x < 10.5
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5

[8] In general, the scorecard-indicated outcome is oriented to the Corporate Family Rating (CFR) for speculative-grade issuers and the senior unsecured rating for investment-grade issuers. For issuers that benefit from ratings uplift due to parental support, government ownership or other institutional support, the scorecard-indicated outcome is oriented to the baseline credit assessment. For more information, see our cross-sector methodology that describes our general approach for assessing government-related issuers. Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. For more information, see our cross-sector methodology that describes principles related to loss given default for speculative grade non-financial companies and also our cross-sector methodology that describes the alignment of corporate instrument ratings based on differences in security and priority of claim. A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section.

Scorecard-Indicated Outcome

Scorecard-Indicated Outcome	Aggregate Weighted Total Factor Score
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

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

6. Appendices

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

Discussion of the Scorecard Factors

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

» Regulatory Framework

» Ability to Recover Costs and Earn Returns

» Diversification

» Financial Strength

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

Factor 1: Regulatory Framework (25%)

Why It Matters

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

Utility rates[9] are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary

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

that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.

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

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

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

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

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

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

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

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

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

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

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

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

How We Assess Consistency and Predictability of Regulation for the Scorecard

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

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

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

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

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

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

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

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

Why It Matters

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

How We Assess Ability to Recover Costs and Earn Returns

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

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

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

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

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

How We Assess Sufficiency of Rates and Returns for the Scorecard

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

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

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

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

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

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

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

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

Factor 3: Diversification (10%)

Why It Matters

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

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

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

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

How We Assess Market Position for the Scorecard

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

Economic diversity is a typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry. In our assessment, we may consider various information sources.[10] We also look at the mix of the utility's sales volumes among customer types, as well as the track record of volume sales and any notable payment patterns during economic cycles. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. While the highest scores in the Market Position sub-factor are reserved for issuers regulated in multiple jurisdictions, when there is only one regulator, we make a differentiation of regimes perceived as having lower or higher volatility.

Issuers with multiple supportive regulatory jurisdictions, a balanced sales mix among residential, commercial, industrial and governmental customers in a large service territory with a robust and diverse economy will generally score higher in this sub-factor. An issuer with a small service territory economy that

[10] For example, in the US, information sources on the diversity and vitality of economies of individual states and metropolitan areas may include Moody's Economy.com.

has a high dependence on one or two sectors, especially highly cyclical industries, will generally score lower in this sub-factor, as will issuers with meaningful exposure to economic dislocations caused by natural disasters.

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

How We Assess Generation and Fuel Diversity for the Scorecard

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

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

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

Factor 3: Diversification (10%)

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

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

Generation and Fuel Diversity	5.00% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges.

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

Factor 4: Financial Strength (40%)

Why It Matters

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

How We Assess It for the Scorecard

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

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

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

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

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

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

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

CFO Pre-Working Capital / Debt

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

CFO Pre-Working Capital Minus Dividends / Debt

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

Debt/Capitalization

This ratio is a traditional measure of balance sheet leverage. The numerator is total debt and the denominator is total capitalization. All of our ratios are calculated in accordance with our standard adjustments[11], but we note that our definition of total capitalization includes deferred taxes in addition to total debt, preferred stock, other hybrid securities, and common equity. Since the presence or absence of deferred taxes is a function of national tax policy, comparing utilities using this ratio may be more meaningful among utilities in the same country or in countries with similar tax policies. High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in bank credit facilities or other financing agreements[12]. A high ratio may result from a regulatory framework that does not permit a robust cushion of equity in the capital structure, or from a material write-off of an asset, which may not have impacted current period cash flows but could affect future period cash flows relative to debt.

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

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

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

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

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

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

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

Factor 4: Financial Strength

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

Notching for Structural Subordination of Holding Companies

Why It Matters

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

Most HoldCos present their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and scorecard scoring is thus based on consolidated ratios. However, HoldCo creditors typically have a secondary claim on the group's cash flows and assets after OpCo creditors. We refer to this as structural subordination, because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and non-utility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors. By contrast, the debt of the HoldCo is typically serviced primarily by dividends that are upstreamed by the OpCos[13]. Under normal circumstances, these dividends are made from net income, after payment of the OpCo's interest and preferred dividends. In most non-financial corporate sectors where cash often moves freely between the entities in a single issuer family, this distinction may have less of an impact. However, in the regulated utility sector, barriers to movement of cash among companies in the corporate family can be much more restrictive, depending on the regulatory framework. These barriers can lead to significantly different probabilities of default for HoldCos and OpCos. Structural subordination also affects loss given default. Under most default[14] scenarios, an OpCo's creditors will be satisfied from the value residing at that OpCo before any of the OpCo's assets can be used to satisfy claims of the HoldCo's creditors. The prevalence of debt issuance at the OpCo level is another reason that structural subordination is usually a more serious concern in the utility sector than for investment grade issuers in other non-financial corporate sectors.

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

How We Assess It

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

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

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

» Specific ring-fencing provisions

» Strict financial covenants at the OpCo level

» Higher leverage at the OpCo level

» Higher leverage at the HoldCo level[15]

» Significant dividend limitations or potential limitations at an important OpCo

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

» Strained liquidity at the HoldCo level

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

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

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

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

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

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

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

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

Assumptions, Limitations and Other Rating Considerations

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

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

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

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

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

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

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

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

Other Rating Considerations

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

Liquidity and Access to Capital Markets

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

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

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

Management Quality and Financial Policy

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

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

Size – Natural Disasters, Customer Concentration and Construction Risks

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

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

Interaction of Utility Ratings with Government Policies and Sovereign Ratings

Compared to most industrial sectors, regulated utilities are more likely to be impacted by government actions. Credit impacts can occur directly through rate regulation, and indirectly through energy, environmental and tax policies. Government actions affect fuel prices, the mix of generating plants, the certainty and timing of revenues and costs, and the likelihood that regulated utilities will experience financial stress. While our evolving view of the impact of such policies and the general economic and financial climate is reflected in ratings for each utility, some considerations do not lend themselves to incorporation in a simple scorecard.[16]

Diversified Operations at the Utility

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

Event Risk

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

Corporate Governance

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

Investment and Acquisition Strategy

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

[16] For more information, see our cross-sector methodology that discusses general principles related to how sovereign credit quality can impact other ratings. A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section.

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

Financial Controls

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

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

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Scorecard

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Factor 3: Diversification (10%)

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

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

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

Factor 4: Financial Strength

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

Appendix B: Approach to Ratings within a Utility Family

Typical Composition of a Utility Family

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

General Approach to a Utility Family

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

In addition to considering individual OpCos under this (or another applicable) methodology, we typically[17] approach a HoldCo rating by assessing the qualitative and quantitative factors in this methodology for the consolidated entity and each of its utility subsidiaries. Ratings of individual entities in the issuer family may be pulled up or down based on the interrelationships among the companies in the family and their relative credit strength.

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

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

» Differentiation of the regulatory frameworks of the various OpCos

» Specific ring-fencing provisions at particular OpCos

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

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

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

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

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

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

[17] See paragraph at the end of this section for approaches to Hybrid HoldCos.

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

Our approach to a Hybrid HoldCo (see definition in Appendix C) depends in part on the importance of its non-utility operations and the availability of information on individual businesses. If the businesses are material and their individual results are fully broken out in financial disclosures, we may be able to assess each material business individually by reference to the relevant Moody's methodologies to arrive at a composite assessment for the combined businesses.[18] If non-utility operations are material but are not broken out in financial disclosures, we may look at the consolidated entity under more than one methodology. When non-utility operations are less material but could still impact the overall credit profile, the difference in business risks and our estimation of their impact on financial performance will be qualitatively incorporated in the rating.

Higher Barriers to Cash Movement with Financing Predominantly at the OpCos

Where higher barriers to cash movement exist on an OpCo or OpCos due to the regulatory framework or debt structural features, ratings among family members are likely to be more differentiated. The degree of separateness may be greater or smaller and is assessed on a case-by-case basis, because situational considerations are important.

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

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

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

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

The greatest separateness occurs where strong regulatory insulation is supplemented by effective ring-fencing provisions that fully separate the management and operations of the OpCo from the rest of the family and limit the parent's ability to cause the OpCo to commence bankruptcy proceedings as well as limiting dividends and cash transfers. Typically, most entities in US utility families (including HoldCos and

18 A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section.

OpCos) are rated within 3 notches of each other. However, it is possible for the HoldCo and OpCos in a family to have much wider notching due to the combination of regulatory imperatives and strong ring-fencing that includes a significant minority shareholder who must agree to important corporate decisions, including a voluntary bankruptcy filing.

Lower Barriers to Cash Movement with Financing Predominantly at the OpCos

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

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

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

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

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

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

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

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

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

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

Regulated Generation Utility: Regulated generation utilities (Regulated Gencos) are utilities that almost exclusively have generation assets, but their activities are generally regulated like those of vertically integrated utilities. This typically means that the purchasers of their output (typically other investor-owned, municipal or cooperative utilities) pay a regulated rate based on the total allowed costs of the Regulated Genco, including a return on equity based on a capital structure designated by the regulator. Companies that have been included in this group include certain generation companies that are not rate regulated in the usual sense of recovering costs plus a regulated rate of return on either equity or asset value. Instead, we have looked at a combination of governmental action with respect to setting feed-in tariffs and directives on how much generation will be built (or not built) in combination with a generally high degree of government ownership, and we have concluded that these companies are currently best rated under this methodology. Future evolution in our view of the operating and/or regulatory environment of these companies could lead us to conclude that they may be more appropriately rated under a related methodology.[19]

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

Transmission-Only Utility: Transmission-only utilities are solely focused on owning and operating transmission assets. The transmission lines these utilities own are typically high-voltage and allow energy producers to transport electric power over long distances from where it is generated (or received) to the transmission or distribution system of a T&D or vertically integrated utility. Unlike most of the other utilities rated under this methodology, transmission-only utilities primarily provide services to other utilities and ISOs. Transmission-only utilities in most parts of the world other than the US have typically been rated under a different methodology.[20]

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

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

19 For more information, see our methodology that describes our general approach for assessing unregulated utilities and unregulated power companies. A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section.

20 For more information, see our methodology that describes our general approach for assessing regulated electric and gas networks. A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section.

Appendix D: Regional and Other Considerations

Notching Considerations for US First Mortgage Bonds

In most regions, our approach to notching between different debt classes of the same regulated utility issuer follows the guidance on notching corporate instrument ratings based on differences in security and priority of claim, including a one notch differential between senior secured and senior unsecured debt.[21] However, in most cases we have two notches between the first mortgage bonds and senior unsecured debt of regulated electric and gas utilities in the US. Wider notching differentials between debt classes may also be appropriate in speculative-grade issuers.[22]

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

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

Securitization

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

In the presentation of US securitization debt in published financial ratios, we make our own assessment of the appropriate credit representation but in most cases follow the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which in turn considers the terms of enabling

21 A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section.

22 For more information, see our cross-sector methodology that describes general principles related to loss given default for speculative-grade companies. A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section.

legislation. As a result, accounting treatment may vary. In most states, utilities have been required to consolidate securitization debt under GAAP, even though it is technically non-recourse.

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

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

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

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

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

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

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

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

Additional considerations for PPAs

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

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

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

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

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

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

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

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

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

Methods for estimating a liability amount for PPAs

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

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

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

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

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

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

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

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

Moody's Related Publications

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

For data summarizing the historical robustness and predictive power of credit ratings, please click here.

For further information, please refer to *Rating Symbols and Definitions*, which is available here.

» contacts continued from page 1

Analyst Contacts:

BUENOS AIRES	+54.11.5129.2600
Daniela Cuan *Vice President - Senior Analyst* daniela.cuan@moodys.com	+54.11.5129.2617

TORONTO	+1.416.214.1635
Gavin MacFarlane *Vice President - Senior Credit Officer* gavin.macfarlane@moodys.com	+1.416.214.3864

LONDON	+44.20.7772.5454
Douglas Segars *Managing Director - Infrastructure Finance* douglas.segars@moodys.com	+44.20.7772.1584

HONG KONG	+852.3551.3077
Vivian Tsang *Associate Managing Director* vivian.tsang@moodys.com	+852.375.815.38

SINGAPORE	+65.6398.8308
Ray Tay *Vice President - Senior Credit Officer* ray.tay@moodys.com	+65.6398.8306

TOKYO	+81.3.5408.4100
Mihoko Manabe *Associate Managing Director* mihoko.manabe@moodys.com	+81.354.084.033
Mariko Semetko *Vice President - Senior Credit Officer* mariko.semetko@moodys.com	+81.354.084.209

Report Number: 1072530

Author
Michael G. Haggarty

Production Associate
Masaki Shiomi

MOODY'S
INVESTORS SERVICE

STAFF-DR-03-006

REQUEST:

Refer to Nowak Direct Testimony, pages 37–39 and Duke Kentucky's response to Commission Staff's Second Request for Information (Staff's Second Request), Item 27c.

a. For the Risk Premium method, identify and explain whether the awarded Return on Equity(ies) (ROE) obtained from Research Regulatory Associates (RRA) were the result of fully litigated rate cases or settlements. Include in the response whether any of the ROEs also included penalties or incentives resulting from specific actions on the part of the utility.

b. Explain what company growth rates are being limited in the Capital Asset Pricing Model (CAPM) Federal Energy Regulatory Commission (FERC) Method and the rationale for the limitation.

c. If the Risk Premium method is a valid approach to estimate regulated utility returns on equity, then explain why that risk premium should not also be applicable as the risk premium in the CAPM method.

d. Provide an update to the CAPM derived ROE estimates using the risk premium estimated in the risk premium method explained on pages 38-39 of Nowak Direct Testimony.

RESPONSE:

a. The authorized returns on equity obtained from Research Regulatory Associates (RRA) include both fully litigated rate cases and settlements. Mr. Nowak has not reviewed the more than 600 cases to determine if any of the decisions included penalties or incentives resulting from specific actions on the part of the utility, and RRA makes no indication as such in its database.

b. In the derivation of the Capital Asset Pricing Model applying the Federal Energy Regulatory Commission Market Risk Premium approach, S&P 500-member companies with Value Line long-term EPS estimates less 0 percent and greater than 20 percent were excluded from the Constant Growth DCF model to estimate the market capitalization-weighted total market return for the S&P 500 Index. The rationale is explained in more detail in response to response to Staff's Third Request, Item 18.

c. The question inappropriately conflates the concepts of a "risk premium" as applied in the "Bond Yield Plus Risk Premium approach" (Risk Premium approach) and the "Market Risk Premium" (MRP) as defined for the application in the CAPM.

In general terms, a risk premium is an incremental return required by an investor as compensation of an incremental level of risk. The Risk Premium approach as described in equation 5 of the Direct Testimony of Joshua C. Nowak, page 38 is based on an analysis of the incremental return required for an equity investment in a vertically integrated electric utility over the 30-year Treasury yield. As described in equation [3] of the Direct Testimony of Joshua C. Nowak, pages 34-35, the term ($r_m - r_f$) represents the Market Risk Premium. The MRP, as defined in the CAPM, is the return required by investors for the equity market as a whole above a risk-free rate of return. Significantly, "m" in the term "r_m" represents the market as whole, which is why the S&P 500 or NYSE Composite Indices are often used as proxies for the broad equity market.

The terms "Risk Premium" as applied in the Risk Premium approach and "Market Risk Premium" as applied in the CAPM are not synonymous and represent two distinct concepts. Since they are not conceptually similar, the “Risk Premium” approach cannot be used in the CAPM.

d. The question in unclear as to how the CAPM could apply the Risk Premium approach to estimate an ROE. Since the Market Risk Premium is estimating the return required by investors for the equity market as a whole and the Risk Premium approach is the incremental return required for an equity investment in a vertically integrated electric utility over the 30-year Treasury yield, these are two distinct estimates of different concepts and are not interchangeable. Using a Market Risk Premium in the CAPM based on equity returns for vertically integrated electric utilities would render Beta estimates calculated relative to the S&P 500 or NYSE Composite Indices meaningless.

PERSON RESPONSIBLE: Joshua C. Nowak

STAFF-DR-03-007

REQUEST:

Refer to Schedule L-1, pages 81 and 85. Confirm that Rate NSU, Street Lighting Service Non-Standard Units and Rate SC, Street Lighting Service – Customer Owned will terminate December 31, 2026. If the rate will not terminate, explain why the termination date remains in the tariff.

RESPONSE:

Confirmed.

PERSON RESPONSIBLE: Bruce L. Sailers

Duke Energy Kentucky
Case No. 2022-00372
STAFF Third Set Data Requests
Date Received: February 17, 2023

STAFF-DR-03-008

REQUEST:

Refer to Schedule L-1, pages 132–136, Rider DIR, Development Incentive Rider. Explain what security, if any, Duke Kentucky requires of customers taking service under Rider DIR.

RESPONSE:

Rider DIR specifies requirements for the customer to obtain credits under the rider but Rider DIR does not require security. Nonetheless, Rider DIR potentially works in tandem with Rider X. Rider X may require a minimum bill provision or a deposit from the customer. But again, those provisions would be found under Rider X and not Rider DIR.

PERSON RESPONSIBLE: Bruce L. Sailers

PUBLIC STAFF-DR-03-009

REQUEST:

Refer to Schedule L-1, pages 161 and 163.

a. Confirm that there are no changes being proposed on these tariff pages.

b. Provide the detailed calculation of the capacity purchase rates.

RESPONSE:

<u>CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment (b) only)</u>

a. Confirmed.

b. The Company's cogeneration tariffs are revised every 2 years. The last revision to the tariffs was filed on February 25, 2022 via the Commission's electronic tariff filing system.[1] The filing was accepted by the Executive Director on March 31, 2022.[2] The calculations of the capacity purchase rates were included with the February 25, 2022 filing under confidential seal. This confidential attachment is attached without change to this request as STAFF-DR-03-009(b) Confidential Attachment.

PERSON RESPONSIBLE: Bruce L. Sailers

[1] TFS2022-00071, *Tariff: Duke Energy Kentucky, Inc. Tariffs for Qualified Cogeneration and Small Power Production Facilities* (Feb. 25, 2022).
[2] *Id.*, Letter of Acceptance (Mar. 31, 2022).

CONFIDENTIAL PROPRIETARY TRADE SECRET

STAFF-DR-03-009(b)
CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

Duke Energy Kentucky
Case No. 2022-00372
STAFF Third Set Data Requests
Date Received: February 17, 2023

STAFF-DR-03-010

REQUEST:

Refer to Schedule L-2.2, page 82, Rider X, Line Extension Policy.

a. Confirm that if the estimated cost of changing or extending the distribution lines to reach a customer's premises is less than $1 million and equals or is less than three times the estimated gross annual revenue and the customer establishes credit in a manner satisfactory to Duke Kentucky, then the customer would not be responsible for the costs of changes to or extending the distribution lines. If not confirmed, explain.

b. Explain what Duke Kentucky would consider satisfactory credit in relation to Rider X.

c. Explain under what circumstances a customer would not be required to enter into an agreement to guarantee a monthly bill of 1 percent of the line extension cost for residential service and 2 percent for nonresidential service when the estimated cost of changing or extending the distribution lines to reach the customer's premises is greater than $1 million or exceeds three times the estimated gross annual revenue.

d. Refer to Schedule L-2.2 generally. Provide all rate design workpapers and revenue models supporting the proposed rate schedules in Excel spreadsheet format with all formulas, rows, and columns unprotected and fully accessible and with all links intact.

RESPONSE:

a. Confirmed. Further, the Company clarifies that the Line Extension Policy is not triggered (i.e., applied) unless the change or extension impacts the primary distribution main line system. Customers are not required to pay for changes or extensions if they do not impact the primary distribution main line system.

b. The Company will assess credit based on certain characteristics such as a Moody's rating of Ba2 or better or an Experian Financial Stability Risk Score of 40 or better.

c. For changes or extensions greater than $1 million or greater than 3 times the estimated gross annual revenue, customers have the option of the minimum bill agreement or paying a contribution in aid of construction (CIAC) amount equal to the cost less the three year estimated gross revenues. If the customer chooses the CIAC option, no agreement is required.

d. Please see STAFF-DR-01-056 Attachment – SCH-M and N – TEST PERIOD, STAFF-DR-01-056 Attachment BLS-2, STAFF-DR-01-056 Attachment BLS-3, STAFF-DR-01-056 Attachment BLS-4, STAFF-DR-01-056 Attachment BLS-5, STAFF-DR-01-056 Attachment BLS-6, STAFF-DR-01-056 Attachment BLS-7, and STAFF-DR-01-056 Attachment BLS-8.

PERSON RESPONSIBLE: Bruce L. Sailers

STAFF-DR-03-011

REQUEST:

Refer to Duke Kentucky's response to Commission Staff's First Request for Information (Staff's First Request), Item 54, Attachment 1. For each year included in the attachment, provide a breakdown of the reconnection charge columns by the following types, listing the amounts billed and number of times billed:

a. Remote Reconnection;

b. Non-Remote Electric Reconnection;

c. Pole Reconnection;

d. Non-Remote After-Hours Reconnection; and

e. Pole Reconnection After Hours.

RESPONSE:

The following table shows the data by year for the periods January 2017 through March 2022. The tables were created by a manual analysis of more than twenty thousand reconnection fee transactions in the revenue datasets, and assignment to each transaction of a fee type based on the dollar amount of the transaction. Of the more than twenty thousand transactions, there were twenty-six transactions for which we were unable to assign a fee type. These transactions appear in the table as "Unknown." Each of these "Unknown" transactions had charges or credits in the amount of $40.44 or $47.94. We do not know the source of these entries.

Row Labels	Column Labels 2017	2018	2019	2020	2021	2022
Unknown						
Sum of TOTALREV				$0	$971	$96
Sum of Count				0	24	2
Remote Reconnection						
Sum of TOTALREV		$11,102	$19,272	$8,282	$36,615	$5,762
Sum of Count		3,218	5,586	1,878	6,227	980
After Hours Reconnection						
Sum of TOTALREV		($25)				
Sum of Count		-1				
Non-Remote Reconnection						
Sum of TOTALREV	$133,906	$64,091	$8,038	$2,444	$8,580	$1,020
Sum of Count	5,372	2,125	107	34	143	17
Pole Reconnections						
Sum of TOTALREV	$49,395	$23,055	$5,250	$1,000	$2,250	$125
Sum of Count	763	267	42	8	18	1
Non-Remote Reconnection after hours						
Sum of TOTALREV		$100	$25	$25	$0	
Sum of Count		4	1	1	0	
Remote Reconnection after hours						
Sum of TOTALREV		$370	$427	$14		
Sum of Count		26	30	1		
Total Sum of TOTALREV	**$183,301**	**$98,693**	**$33,011**	**$11,765**	**$48,415**	**$7,003**
Total Sum of Count	**6,135**	**5,639**	**5,766**	**1,922**	**6,412**	**1,000**

The following tables show revised 2022 reconnection revenues and counts by customer class and type. The 2022 numbers below are corrections to the numbers that the Company provided in STAFF-DR-01-054 Attachment 1. The "CMS" column shows the numbers for January through March that were billed in CMS. The "SAP" column shows the numbers for April through August that were billed in the Customer Connect billing system.

Sum of TOTALREV		2022		
Row Labels		Total CMS	Total SAP	Total Both
Commercial		**$1,590**	**$323**	**$1,914**
Unknown		$0	$0	$0
Remote Reconnection		$570	$323	$894
Non-Remote Reconnection		$1,020	$0	$1,020
Pole Reconnections		$0	$0	$0
Residential		**$5,413**	**$1,176**	**$6,589**
Unknown		$96	$0	$96
Remote Reconnection		$5,192	$1,176	$6,368
Pole Reconnections		$125	$0	$125
Industrial		**$0**	**$12**	**$12**
Remote Reconnection		$0	$12	$12
Grand Total		**$7,003**	**$1,511**	$8,514

Sum of Count Row Labels	Column Labels 2022	CMS Count	SAP Count	Total Count
Commercial		**114**	**52**	**166**
Unknown		-	-	-
Remote Reconnection		97	52	149
Non-Remote Reconnection		17	-	17
Pole Reconnections		-	-	-
Residential		**886**	**200**	**1,086**
Unknown		2	-	2
Remote Reconnection		883	200	1,083
Pole Reconnections		1	-	1
Industrial		**-**	**2**	**2**
Remote Reconnection		-	2	2
Grand Total		**1,000**	**254**	**1,254**

PERSON RESPONSIBLE: James E. Ziolkowski

Duke Energy Kentucky
Case No. 2022-00372
STAFF Third Set Data Requests
Date Received: February 17, 2023

STAFF-DR-03-012

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 11(d).

a. Provide, by month, for the period beginning January 2021 to present, the number of calls Duke Kentucky received from customers that authenticated in the Interactive Voice Response (IVR) system or that mentioned late-payment billing topics when describing their reason for calling the IVR system.

b. If different from above, provide, by month, for the period beginning January 2021 to present, the number of phone calls Duke Kentucky has received from late paying customers.

RESPONSE:

a.

Date	Number of Authenticated Calls	Date	Number of Authenticated Calls
1/1/2021		4/1/2022	2,399
2/1/2021		5/1/2022	1,844
3/1/2021		6/1/2022	2,237
4/1/2021		7/1/2022	2,398
5/1/2021		8/1/2022	2,799
6/1/2021		9/1/2022	2,472
7/1/2021	2,679	10/1/2022	2,594
8/1/2021	4,569	11/1/2022	2,772
9/1/2021	4,360	12/1/2022	3,125
10/1/2021	5,109	1/1/2023	2,732
11/1/2021	5,430		
12/1/2021	5,685		
1/1/2022	7,915		
2/1/2022	7,854		
3/1/2022	6,949		

Note: January 2021-June 2021: This was prior to the IVR enhancement and no such data was tracked.

Please note that the data prior to April 2022, included in Colley Exhibit 1, is data from Duke Energy Kentucky legacy CIS. The data for April 2022-January 2023 is from the new Duke Energy Kentucky billing system. While the data after April 2022 trends much lower, it cannot be directly compared to the data used in the late payment analysis (March 2021-March 2022). There are a few key drivers:

- Disconnections were suspended from April – July 2022 depressing call volumes overall
- In the legacy system, customers would be eligible for an installment plan when they had a past due balance. In the new CIS, customers have the option to create an installment plan for either a past due or current balance.
- The codes originally used to identify and query authenticated late-payer callers were retired and replaced with new codes. The new codes have specific definitions for the new billing system and are not direct copies of the legacy codes. The impact of these code changes on the late payment analysis require evaluation and would require extensive time to analyze and complete. Colley Exhibit 1 was prepared for the filing based on data substantiated in the system of record at that time.

b. See response to (a) above**.**

PERSON RESPONSIBLE: Jacob S. Colley

Duke Energy Kentucky
Case No. 2022-00372
STAFF Third Set Data Requests
Date Received: February 17, 2023

STAFF-DR-03-013

REQUEST:

Refer to the response to Staff's Second Request, Item 13b.

a. Explain whether the charging equipment installed by Duke Kentucky will allow for third-party payments.

b. Explain whether the charging equipment installed by Duke Kentucky will display the kWh usage or be billed in such a way that kWh usage can be determined for each charging session. If not, explain how the kWh usage will be tracked per customer.

RESPONSE:

a. Yes, equipment available within the EVSE Program that Duke Energy Kentucky is proposing will allow for third-party payments as a benefit to the participating customers in the program. The Duke Energy account holder and EVSE Program participant that desires to collect fees from third party users would select a networked charger option and determine the fee amount and structure to assess via networking software. Duke Energy Kentucky is not proposing to directly accept, collect, and remit third-party payments for charging sessions.

b. The EVSE program considers the Duke Energy account holder and program participant to be the customer. Third party EV drivers may use chargers if access is granted by the participating customer. In such cases, to facilitate charging fee collection by the customer, the EVSE program will provide access to networked chargers that are capable of capturing and displaying per charging session kWh consumption and fees assessed to the driver. In some cases, this information is displayed on the networking software a smart phone app or website rather than on the EV charging hardware itself.

PERSON RESPONSIBLE: Cormack C. Gordon

STAFF-DR-03-014

REQUEST:

Refer to the response to Staff's Second Request, Item 15. Explain why the Line Extension Policy is an appropriate basis for the Make Ready Credit.

RESPONSE:

First, the proliferation of EV technologies will – and does – represent meaningful and permanent addition of load to the electric system. As noted in response to several discovery requests, these loads can also help create better system utilization and downward rate pressure. These are loads for which investment in infrastructure can be offset by future revenues. Line Extension Policy is the long-accepted structure in place for fulfilling the company's obligation to invest in new or upgraded infrastructure to serve customers.

Secondly, these are also loads for which customers seek assistance in the form of guidance, assurance and reduction of capital barriers. Unlike when adding more traditional loads, customers that desire to convert to EV technology often need programmatic assistance in order to so do.

Putting these two themes together, the Line Extension Policy becomes an appropriate and useful basis on which to tie make ready credit amounts to the value these new loads bring to the system.

PERSON RESPONSIBLE: Cormack C. Gordon

STAFF-DR-03-015

REQUEST:

Refer to the response to Staff's Second Request, Item 17.

a. Explain whether Duke Kentucky considers the Make Ready Credit program an incentive program.

b. Explain whether Duke Kentucky has explored free riders, or customers who would have installed charging equipment without the credit incentive, in the Make Ready Credit program.

RESPONSE:

a. No, Duke Energy Kentucky does not consider the Make Ready Credit program (MRC) an incentive program. The MRC is more akin to investments in the distribution system, extending concepts of the line extension policy to assist customers installing make ready infrastructure in an affordable and reliable manner, thus simplifying EV adoption.

However, the MRC, as well as the proposed EVSE program, set the stage and serve as enablers for future EV load management programs, which may be categorized as demand side management program(s).

b. No, Duke Energy Kentucky has not explored free ridership for the MRC because the MRC is neither considered an energy efficiency nor a demand response program.

PERSON RESPONSIBLE: Cormack C. Gordon

Duke Energy Kentucky
Case No. 2022-00372
STAFF Third Set Data Requests
Date Received: February 17, 2023

STAFF-DR-03-016

REQUEST:

Refer to the response to Staff's Second Request, Item 20, Attachment. Explain the drivers for the large undepreciated balance of East Bend, even using the proposed depreciation rates and the later expected retirement date.

RESPONSE:

(a) Based on current depreciation rates:

The large undepreciated balance is primarily due to the current depreciation rates were based on the 2016 Depreciation Study (December 2016). There have been new Plant in Service additions since.

(b) Based on proposed depreciation rates:

The undepreciated balance is primarily due to Plant in Service additions for 2022; which was after the date of the proposed study (December 2021); and Land (not depreciating).

PERSON RESPONSIBLE: Huyen C. Dang

STAFF-DR-03-017

REQUEST:

Refer to the response to Staff's Second Request, Item 26(c)–(d).

a. Provide documentation to support the following statement: "Mr. Nowak is aware that Yahoo! Finance Beta estimates are based on five years of monthly returns. Five years of monthly returns, or 60 total observations, may not produce a statistically robust relationship for estimating Beta so they should not be included in the CAPM analysis."

b. Provide an update to all analyses that, in addition to Value Line and Bloomberg beta values, include Yahoo! Finance adjusted beta values.

RESPONSE:

a. Please see STAFF-DR-03-017(a) Attachment 1, which provides an example of a Yahoo! Finance's Beta estimate for one of Mr. Nowak's proxy companies – ALLETE, Inc. Based on the description "Beta (5Y Monthly)," this served as the basis for Mr. Nowak to conclude that Yahoo! Finance Beta estimates are based on five years of monthly returns. Based on further research, provided as STAFF-DR-03-017(a) Attachment 2, Yahoo! Finance Beta has previously indicated that Beta estimates are based on three years of monthly returns, rather than five years of monthly returns. This only exacerbates the concern raised in response to STAFF-DR-02-026(c) that 36 total observations may not produce a statistically robust relationship for estimating Beta so they should not be included in the CAPM analysis. However, more concerning is that Mr. Nowak was not able to replicate Yahoo! Finance's Beta estimate calculations to confirm that they are based on either three years of monthly returns or five years of monthly returns. As such, Mr. Nowak does not support the application of Yahoo! Finance Beta coefficients in the estimate of the CAPM as he has found no evidence that they are consistent and reliable estimates.

b. Mr. Nowak maintains a process to capture Value Line and Bloomberg Beta coefficient estimates on a monthly basis at the end of each month, with the most recent data as of January 31, 2023, which preceded this request. Given the concerns cited in subpart (a), Mr. Nowak does not capture Yahoo! Finance Beta coefficients with any regularity. Therefore, Mr. Nowak does not possess the requested Yahoo! Finance data on the same basis as his other ROE analytical components.

PERSON RESPONSIBLE: Joshua C. Nowak

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ALLETE, Inc. (ALE)

NYSE - NYSE Delayed Price. Currency in USD

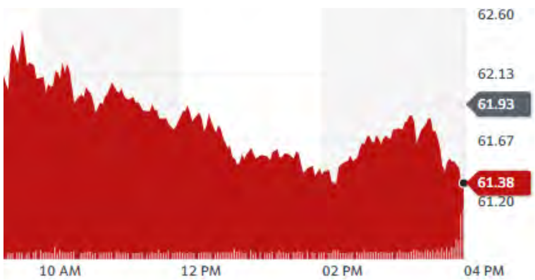
Follow | Visitors trend 2W ↓ 10W ↑ 9M ↑ | Quote Lookup

61.38 -0.55 (-0.89%) | **61.38** 0.00 (0.00%)

At close: February 23 04:00PM EST | After hours: Feb 23, 06:03PM EST

Summary | Company Insights | Chart | Conversations | Statistics | Historical Data | Profile | Financials | Analysis | Options | Holders | Sustainability

1D 5D 1M 6M YTD 1Y 5Y Max | Full screen



Trade prices are not sourced from all markets

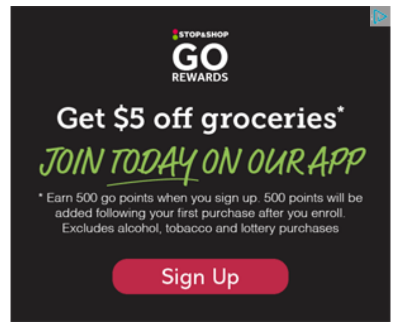


Chart Events

Bullish *pattern detected*

Short-term KST

View all chart patterns

Performance Outlook

Short Term 2W - 6W ↑	Mid Term 6W - 9M ↓	Long Term 9M+ ↑

Previous Close	61.93
Open	62.13
Bid	60.97 x 1000
Ask	0.00 x 1000
Day's Range	61.36 - 62.45
52 Week Range	47.77 - 68.46
Volume	284,180
Avg. Volume	335,000

Market Cap	3.514B
Beta (5Y Monthly)	0.72
PE Ratio (TTM)	18.16
EPS (TTM)	3.38
Earnings Date	May 03, 2023 - May 08, 2023
Forward Dividend & Yield	2.71 (4.38%)
Ex-Dividend Date	Feb 14, 2023
1y Target Est	65.17

Fair Value

XX.XX

Overvalued

-14% Est. Return

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IDA IDACORP, Inc.	104.04	-0.71	-0.68%
PNM PNM Resources, Inc.	49.25	-0.19	-0.38%

Similar to ALE

Symbol	Last Price	Change	% Change
MGEE MGE Energy, Inc.	72.07	+0.47	+0.66%
NWE NorthWestern Corporation	57.64	-0.17	-0.29%
AVA Avista Corporation	41.69	-0.08	-0.19%
BKH Black Hills Corporation	62.36	-0.47	-0.75%
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Earnings ›

Consensus EPS

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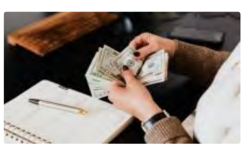

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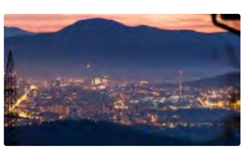

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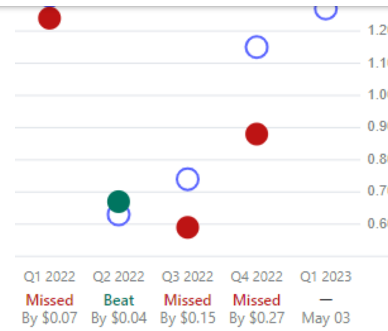

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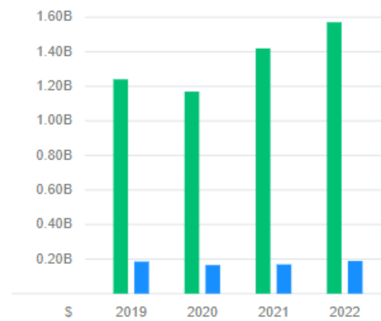

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Profitability

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Income Statement

Balance Sheet

Cash Flow Statement

Trading Information

Stock Price History

Beta

The Beta used is Beta of Equity. Beta is the monthly price change of a particular company relative to the monthly price change of the S&P500.; The time period for Beta is 3 years (36 months) when available.

52-Week Change

The percentage change in price from 52 weeks ago.

S&P500; 52-Week Change

The S&P; 500 Index's percentage change in price from 52 weeks ago.

52-Week Low

This price is the lowest Price the stock traded at in the last 12 months. This could be an intraday low.

50-Day Moving Average

A simple moving average that is calculated by dividing the sum of the closing prices in the last 50 trading days by 50.

200-Day Moving Average

A simple moving average that is calculated by dividing the sum of the closing prices in the last 200 trading days by 200.

Share Statistics

Dividends and splits

STAFF-DR-03-018

REQUEST:

Refer to the response to Staff's Second Request, Item 27c. The response did not address the specific question as to rationale for and reasonableness of the CAPM FERC Method of limiting company growth rates to between 0 and 20 percent. Explain the rationale and reasonableness of the limitation.

RESPONSE:

In Opinion No. 569, FERC found that "S&P 500 companies with growth rates that are negative or in excess of 20 percent should be excluded from the CAPM analysis because their growth rates are not representative of sustainable growth rates." In support of its position, FERC referred to academic research as an example, "Principles of Corporate Finance, Richard A. Brealey and Stewart C. Myers explain that 'No firm can continue growing at 20 percent per year forever, except possibly under extreme inflationary conditions.'" While this may be true for an individual firm, the purpose of the market risk premium is to estimate the total return that investors would require for an investment in the broad market, as measured by the S&P 500 Index and the S&P 500 Index regularly includes companies with both high growth rates and low or negative growth rates. As described in Direct Testimony of Joshua C. Nowak, page 37, line 15, FERC's approach is a more conservative convention in estimating the Market Risk Premium.

PERSON RESPONSIBLE: Joshua C. Nowak

STAFF-DR-03-019

REQUEST:

Refer to the response to Staff's Second Request, Item 31b. For each regulation identified, explain whether Duke Kentucky would expect to incur compliance costs for East Bend, assuming that it continues to operate when the regulation goes into effect. If so, provide any known costs and supporting documentation.

RESPONSE:

In the response to STAFF-DR-02-031(b), Duke Energy Kentucky identified six EPA rulemaking initiatives that the company is monitoring. As of today, none of these have had any significant developments that suggest that additional costs will be required. While East Bend has already made extensive investments in its environmental systems and is well positioned going forward, some of these rulemakings could result in additional costs depending upon what EPA ultimately decides. Because these are pending rules, it is not possible to estimate any additional costs at this time.

PERSON RESPONSIBLE: J. Michael Geers

STAFF-DR-03-020

REQUEST:

Refer to the response to Staff's Second Request, Item 34. Explain whether Duke Kentucky will file a marginal cost study with the Commission for each Rider DIR contract submitted for approval. If not, explain why not.

RESPONSE:

The Company will file a marginal cost study with the Commission for each Rider DIR contract submitted for approval.

PERSON RESPONSIBLE: Bruce L. Sailers

Duke Energy Kentucky
Case No. 2022-00372
STAFF Third Set Data Requests
Date Received: February 17, 2023

STAFF-DR-03-021

REQUEST:

Refer to the response to Staff's Second Request, Item 38b. Provide the adjustment necessary to remove the proposed base rate roll in of plant in service related to Rider Environmental Surcharge Mechanism.

RESPONSE:

Please see STAFF-DR-03-021 Attachment for the adjustment necessary to remove the proposed base rate roll in of plant in service related to Rider Environmental Surcharge Mechanism. The adjustment will reduce rate base by $53,795,072, increase operating income by $5,002,128 and reduce the revenue deficiency by $12,075,851. Please see AG-DR-02-040 Attachment 3 for the support of the adjustments.

PERSON RESPONSIBLE: Lisa D. Steinkuhl

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2022-00372
OVERALL FINANCIAL SUMMARY
FOR THE TWELVE MONTHS ENDED JUNE 30, 2024

SCHEDULE A
PAGE 1 OF 1

LINE NO.	DESCRIPTION	SUPPORTING SCHEDULE REFERENCE	FORECASTED PERIOD	ADJUSTMENT TO REMOVE PROPOSED ESM BASE RATE ROLL IN	FORECASTED PERIOD W/O ESM
1	Rate Base	B-1	1,176,674,865	($53,795,072)	$1,122,879,793
2	Operating Income	C-2	32,212,101	5,002,128	$37,214,229
3	Earned Rate of Return (Line 2 / Line 1)		2.738%		3.314%
4	Rate of Return	J-1	7.526%		7.526%
5	Required Operating Income (Line 1 x Line 4)		88,556,550	(4,048,617)	84,507,933
6	Operating Income Deficiency (Line 5 - Line 2)		56,344,449	(9,050,745)	47,293,704
7	Gross Revenue Conversion Factor	H	1.3342383		1.3342383
8	Revenue Deficiency (Line 6 x Line 7)		75,176,922	(12,075,851)	63,101,071

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2022-00372
JURISDICTIONAL RATE BASE SUMMARY
AS OF JUNE 30, 2024

SCHEDULE B-1
PAGE 1 OF 1

LINE NO.	RATE BASE COMPONENT	SUPPORTING SCHEDULE REFERENCE	13 MONTH AVG. FORECAST PERIOD	ADJUSTMENT TO REMOVE PROPOSED ESM BASE RATE ROLL IN	13 MONTH AVG. FORECAST PERIOD W/O ESM
1	Adjusted Jurisdictional Plant in Service	B-2	$2,247,062,477	(67,432,275)	2,179,630,202
2	Accumulated Depreciation and Amortization	B-3 / B-3.2	($863,836,939)	(8,686,596)	(855,150,343)
3	Net Plant in Service (Line 1 + Line 2)		$1,383,225,538	(58,745,679)	1,324,479,859
4	Construction Work in Progress	B-4	$0		
5	Cash Working Capital Allowance	B-5	$5,424,742		$5,424,742
6	Other Working Capital Allowances	B-5	$45,233,909		$45,233,909
7	Other Items:				
8	Customers' Advances for Construction	B-6	$0		
9	Investment Tax Credits	B-6	$0		
10	Deferred Income Taxes	B-6	($205,889,990)	(4,950,607)	($200,939,383)
11	Excess ADIT	B-6	($51,319,334)		($51,319,334)
12	Other Rate Base Adjustments				
13	Jurisdictional Rate Base (Line 3 through Line 12)		$1,176,674,865	($53,795,072)	$1,122,879,793

Duke Energy Kentucky
Case No. 2022-00372
STAFF Third Set Data Requests
Date Received: February 17, 2023

STAFF-DR-03-022

REQUEST:

Refer to the response to Staff's Second Request, Item 40, Attachment. Confirm that Duke Kentucky employees exclusively perform the services listed below. If not confirmed, explain.

a. Non-Remote Electric Reconnection;

b. Pole Reconnection;

c. Non-Remote After-Hours Reconnection;

d. Pole Reconnection After Hours; and

e. Collection Charge (Field Visit).

RESPONSE:

a. Confirmed.

b. Confirmed.

c. Confirmed.

d. Confirmed.

e. Confirmed.

PERSON RESPONSIBLE: Bruce L. Sailers

STAFF-DR-03-023

REQUEST:

Refer to the response to Staff's Second Request, Item 41, in which Duke Kentucky states that if the distribution main line system is impacted by a customer's desired change in installation, the customer is responsible for the costs in excess of the 36-month revenue credit in accordance with the line extension policy. Reconcile the current line extension policy allowing for this when it currently only applies to situations in which distribution lines are extended, and not to a customer's request for a change in installation.

RESPONSE:

The current line extension policy does not apply to changes in installations. However, currently, in determining the cost the customer must pay for a change in installation when the primary distribution main line system is impacted, the Company has historically provided a reduction in the cost to the customer equal to the estimated 36 months of revenue from the change, similar to the line extension policy. See also the Company's response to STAFF-DR-03-010. The Company has applied these policies consistently and therefore proposes to connect them directly through the requested tariff changes.

PERSON RESPONSIBLE: Bruce L. Sailers

STAFF-DR-03-024

REQUEST:

Refer to the response to Staff's Second Request, Item 47(e). Explain what Duke Kentucky will consider a "large investment in infrastructure" in relation to Rider X.

RESPONSE:

The Company has specified the $1 million investment amount as a "large investment". The criteria related to an agreement length of more than 5 years is not specified and would be related to the Company's available investment budget as well as the Customer's flexibility in service requirements across multiple years. The Company is willing to specify a table for agreement length based on investment required if preferred by the Commission. The table can be filed with the Commission within 30 days after receiving the final order in this case and can be contingent upon Staff's review.

PERSON RESPONSIBLE: Bruce L. Sailers

STAFF-DR-03-025

REQUEST:

Refer to the response to Staff's Second Request, Items 49(a) and (b), in which Duke states that the fees are intended to cover program costs for charger removal/relocation with penalizing the customer. Confirm that those responses should state that the fees are intended to cover program costs for charger removal/relocation without penalizing the customer. If not confirmed, explain.

RESPONSE:

Confirmed. Response to Staff's Second Request, Items 49(a) and (b), should state that the fees are intended to cover program costs for charger removal/relocation without penalizing the customer.

PERSON RESPONSIBLE: Cormack C. Gordon

STAFF-DR-03-026

REQUEST:

Refer to the response to Staff's Second Request, Items 49(a) and (b). Explain whether the removal/relocation of the charging stations would be performed by Duke Kentucky employees, outside contractors, or a combination of both labor forces. If any labor is performed by someone other than a Duke Kentucky employee, explain how that decision would be made.

RESPONSE:

The EVSE program will utilize qualified electrical contractors to install, remove, or relocate charging stations. This approach allows the Company, particularly in the early stages of the program, to leverage a variable cost labor source on an as needed basis. Contractors will be selected based on their experience in EV charger installations. The program may evaluate utilizing internal Duke Energy employee labor in the future.

PERSON RESPONSIBLE: Cormack C. Gordon

Duke Energy Kentucky
Case No. 2022-00372
STAFF Third Set Data Requests
Date Received: February 17, 2023

STAFF-DR-03-027

REQUEST:

Refer to the response to Staff's Second Request, Item 53(a), regarding Rider GP, GoGreen Kentucky Rider. If Duke Kentucky were to decrease the GoGreen rate outside of the annual filing, explain when the tariff sheet reflecting the decrease would be submitted to the Commission in relation to the date of the actual decrease. Explain how Duke Kentucky would notify customers participating in Rider GP of the rate decrease.

RESPONSE:

The Company will file the revised tariff sheet a minimum of 30 days prior to the rate decrease taking effect. Notification to Rider GP participants of the rate decrease will be mailed no later than the date of the revised tariff filing.

PERSON RESPONSIBLE: Bruce L. Sailers

STAFF-DR-03-028

REQUEST:

Refer to the Response to Staff's Second Request, Item 55(b), which was seeking information regarding the field collection charge. Provide the information requested for field collection charges.

RESPONSE:

Field collection charges are included in Schedule M in the Other Miscellaneous Revenue section as part of the Other Miscellaneous line item. The amount included for Field Collection Charges is $10,644. As discussed in STAFF-DR-02-055(a), the total forecasted Miscellaneous Revenues in account 451100 of $249,996 was forecasted based on historical averages. Since the revenues were forecasted in total and not by specific types of revenue, the total was allocated to various types of miscellaneous revenues using the actual revenue types in account 451100 from calendar year 2021. In 2021, Field Collection Charges were 4.26% of the total. The allocated portion of the forecasted miscellaneous revenues for field collection charges is $249,996 * 4.26% = $10,644. Rounding deviations can result in slight differences in the final values.

PERSON RESPONSIBLE: Bruce L. Sailers

Duke Energy Kentucky
Case No. 2022-00372
STAFF Third Set Data Requests
Date Received: February 17, 2023

STAFF-DR-03-029

REQUEST:

Explain how Duke Kentucky offers its generating units in the PJM Interconnection LLC (PJM) energy markets.

RESPONSE:

For this response, Duke Energy Kentucky assumes that "offers" refers to the methods used for the calculation of the (1) financial parameters of the PJM price-based offer (incremental cost, startup cost, and no-load cost offers), the (2) commitment status of the PJM offer (Must Run, Economic, Unavailable, or Emergency), and the (3) physical parameters of the unit offer (capability, startup time, ramp rate, etc.). Not included in this response is the cost-based offer, which is in practice used much less often by PJM to dispatch and commit the Duke Energy Kentucky units than the price-based offer. Additionally, ancillary service offers are not included in this response.

East Bend:

(1) Financial Parameters:

The Company uses the replacement (market) price of coal delivered to East Bend for purposes of calculating the incremental cost and no-load cost offers to PJM. For the incremental cost offer, the coal price is multiplied by the units incremental heat rate at each unit loading point to calculate the incremental cost offer. For the no-load cost offer, the coal price is multiplied by the units coal consumption at 0 MW to calculate the no-load cost offer. Additionally, an emissions component and variable O&M component is added to each as applicable.

The Company uses the market price of fuel oil delivered to East Bend for purposes of calculating the startup cost offer to PJM. The unit's startup cost offer is calculated based on the expected amount of fuel oil consumed for a hot, intermediate, or cold startup multiplied by the price of fuel oil.

2) Commitment Status:

Each business day, Duke Energy Kentucky performs a simulated commitment and dispatch of the East Bent unit in the PJM market with the result being a forecast of the energy revenue, variable costs, and resulting energy margin (difference in revenue and variable cost) by day for the next 7 days. This analysis helps inform the commitment status offer, but doesn't necessary determine the offer, since unit commitment of a coal-fired generating unit includes many other factors such as unit availability and capability, length of the PJM Day-Ahead market (24 hours), ability or likelihood of PJM committing the generating unit, impact of PJM billing line item (BLI) credits or charges, potential for a PJM capacity performance (CP) event, minimum up and down time, startup time and cost, required testing, and risk of cycling the unit among other factors.

When available, currently East Bend is typically offered into the PJM Day-Ahead and Real-Time markets with a Must Run commitment offer status to best optimize the unit's availability for dispatch in PJM. Although less common, there are times that do warrant offering the unit with an Economic status to PJM, allowing PJM to determine the commitment of the unit. Forecasts show that in the future, there will be more instances where the revenues received from operation of the unit are projected to be less than the unit's variable costs, and thus the unit would likely be offered to PJM with an Economic commitment offer and potentially be off-line or de-committed by PJM. Models suggest that offering the unit with an Economic commitment status will increase in the future.

3) Physical parameters:

The physical offer parameters of the unit's offer are made generally equal to the unit's actual capability and can change frequently.

<u>Woodsdale:</u>

(1) Financial Parameters:

When operating on natural gas, the Company uses the market price of natural gas delivered to Woodsdale Station for purposes of calculating the incremental cost, no-load cost, and startup cost offers to PJM. This gas cost may include an adjustment for potential additional gas pipeline costs, such as an Operation Flow Order (OFO) cost, or an adjustment for changes in the price of natural gas between when the unit is offered and committed.

When operating on fuel oil, the Company uses the market price of fuel oil delivered to Woodsdale Station for purposes of calculating the incremental cost, no-load cost, and startup cost offers to PJM.

For the incremental cost offer, the fuel price (natural gas or fuel oil) is multiplied by the incremental heat rate at each unit loading point to calculate the incremental cost offer. For the no-load cost offer, the fuel price (natural gas or fuel oil) is multiplied by the units' fuel consumption at 0 MW to calculate the no-load cost offer. Additionally, an emissions component and variable O&M component is added to each as applicable.

The Company uses the market price of fuel (natural gas or fuel oil) delivered to Woodsdale for purposes of calculating the startup cost offer to PJM. The units' startup cost offer is calculated based on the expected amount of fuel consumed for a hot, intermediate, or cold startup multiplied by the price of fuel oil. This gas cost may include an adjustment for potential additional gas pipeline costs, such as an Operational Flow Order (OFO) cost, or an adjustment for changes in the price of natural gas between when the unit is offered and committed. Additionally, an emissions component and variable O&M component is added as applicable

2) Commitment Status:

   When available, the Company's Woodsdale units are typically offered with an Economic status into the PJM markets unless there is an operational necessity to commit the unit as Must Run, such as for unit testing.

3) Physical parameters:

   The physical offer parameters of the units' offer are made generally equal to the units' actual capability and can change frequently.

PERSON RESPONSIBLE: John D. Swez

STAFF-DR-03-030

REQUEST:

Refer to Sailers Direct Testimony, page 30.

a. Identify how, specifically, the Company will utilize the approved cost of service study (COSS) from this proceeding in the preparation of the net metering revisions.

b. Provide the unit costs, or other calculations, Duke Kentucky will use from its COSS to inform its NEM rate revisions, include any workpapers to support the calculations of costs.

RESPONSE:

a. The approved COSS from this proceeding will provide the framework for the approved revenue requirements for each rate class. This framework will be utilized as an input to the determination of the cost to serve new net metering customers.

b. There are no calculations of unit costs or other values available at this time that the Company will use to inform its NEM rate revisions. However, for the excess generation credit for NEM and programs that recognize marginal value, the Company believes the CEC program methodology for calculating avoided costs may be useful in determining the excess generation credit provided to new NEM participants.

PERSON RESPONSIBLE: Bruce L. Sailers

Duke Energy Kentucky
Case No. 2022-00372
STAFF Third Set Data Requests
Date Received: February 17, 2023

STAFF-DR-03-031

REQUEST:

Refer to schedules FR 16(7)(v)-1 through FR 16(7)(v)-25 and workpaper FR-16(7)(v). Provide in Excel spreadsheet format with all formulas, rows, and columns unprotected and fully accessible and with all links intact.

RESPONSE:

Please see the response to STAFF-DR-01-056.

PERSON RESPONSIBLE: James E. Ziolkowski

STAFF-DR-03-032

REQUEST:

Refer to BLS-5. Provide the Exhibit in Excel spreadsheet format with all formulas, rows, and columns unprotected and fully accessible with all links intact. Narratively explain Duke Kentucky's calculations in the Exhibit and how the calculations support the charges.

RESPONSE:

See response to STAFF-DR-01-056 Attachment BLS-5. In the RATE CALC tab, the Company calculates charges for Rate RS-TOU-CPP that are revenue neutral to the Rate RS revenue requirement. The following bullets describe the process:

- Moving down Column B, the revenue requirement less Rider FAC is determined.
- The number of residential bills and total amount of kWh are copied from the values in Schedule M related to Rate RS.
- The proposed customer charge is kept the same as Rate RS and revenues calculated for the customer charge.
- As shown in cell B24, the target revenue requirement for the Rate RS-TOU-CPP energy charges is $160,328,551.
- To determine the $/kWh charge for each Rate RS-TOU-CPP block, the kWh must be allocated to each block.
- KWh allocation factors are computed from the same Rate RS load research information used in the cost of service study. These hourly kWh values are summed into the appropriate blocks which provide allocation percentages in cells B27:B31

of the Rate Calc tab. And subsequently, the total Rate RS kWh is allocated into the Rate RS-TOU-CPP blocks.

- As a guide for the relative value of the charges between the kWh blocks, the Company leverages recent PJM LMP average values within each block. Those values are in cells D27:D31. After review of these values and the potential behavioral customer impacts the price signals suggest, the Company proposes the ratios in cells E27:E31.
- Using the ratios proposed, the proposed $/kWh charges in cells F27:F31 are calculated to result in the collection of the revenue neutral revenue requirement.

PERSON RESPONSIBLE: Bruce L. Sailers

Duke Energy Kentucky
Case No. 2022-00372
STAFF Third Set Data Requests
Date Received: February 17, 2023

STAFF-DR-03-033

REQUEST:

Describe Duke Kentucky's residential and commercial metering technology and capabilities.

a. Confirm all residential meters already capable of supporting the new RES-TOU-CPP rate. If not, explain when that is expected.

b. Confirm whether Duke Kentucky requires a different meter for the RES-TOU-CPP or NEM customers. If so, explain the differences in the meters, including any price or labor considerations. Provide the estimated costs of additional meters including installation and truck rolls, where applicable.

c. Confirm that customers under current NEM rates have the ability to be billed under a time of use rate. If they do, explain the specific process. If they do not, explain why not and what would be needed to accomplish this type of billing.

RESPONSE:

a. The Company's standard residential smart meter is capable of supporting the new RS-TOU-CPP rate. However, the Company is in the process of configuring the rate in the Company's billing system. No issues are anticipated at this time and the Company has the expectation that the new Rate RS-TOU-CPP will be available to customers upon approval by the Commission in approximately July or August 2023. Customers participating in Rider AMO, Advanced Meter Opt-out, are not eligible to participate in the new, optional rate.

b. The Company's standard residential smart meter is capable of supporting both the proposed Rate RS-TOU-CPP and net metering. However, customers participating in Rider AMO, Advanced Meter Opt-out, are not eligible to participate in these options.

c. The Company confirms that we are in the process of configuring Rate RS-TOU-CPP, including discussions on the ability to concurrently participate in net metering, in the Company's billing system. No issues are anticipated at this time and the Company has the expectation that the new Rate RS-TOU-CPP will be available to customers upon approval by the Commission in approximately July or August 2023. However, customers participating in Rider AMO would not be eligible.

The Company anticipates filing for net metering revisions within 60 days of a Commission order in the case. If in the interim period between the order in this case and the order in the yet-to-be filed net metering case, no customers participate in both the new Rate RS-TOU-CPP and net metering, there would be no need to configure the billing system to accommodate the current net metering program for Rate RS-TOU-CPP. The Company could wait to configure Rate RS-TOU-CPP with the new net metering program.

Nonetheless, a customer participating in the current net metering program and Rate RS-TOU-CPP will be billed as follows. Rate RS-TOU-CPP has multiple time period blocks during any particular day. If a customer is on net metering, these blocks are tracked independently for monthly netting purposes. For example, with a customer on Rate RS, the monthly netting process occurs and there is a "kWh bank" that is tracked from month to month and applied during the billing process as applicable from month to month. Under the Company's time of use rate, the kWh bank is separated into 4 kWh banks; one for each of the periods: Discount, Off-Peak, On-Peak, and Critical Peak. Using the 4 separate kWh banks in the same manner as the single kWh bank for Rate RS customers, net metering will be billed similarly for Rate RS-TOU-CPP.

PERSON RESPONSIBLE: Bruce L. Sailers

Duke Energy Kentucky
Case No. 2022-00372
STAFF Third Set Data Requests
Date Received: February 17, 2023

STAFF-DR-03-034

REQUEST:

Reference Direct Testimony of Paul Halstead (Halstead Direct Testimony), pages 14–17.

a. Explain whether Duke Kentucky expects its revised net metering to have the same components as the illustrative Clean Energy Connection (CEC) value presented in Attachment PLH-1.

b. Provide Confidential Attachments PLH-2 and PLH-3 and all supporting workpapers in Excel spreadsheet format with all formulas, rows, and columns unprotected and fully accessible and with all links intact.

c. If not already provided in response to Item b above, provide all underlying workpapers, analysis, and raw data in Excel spreadsheet format with all formulas, rows, and columns unprotected and fully accessible, to support Duke Kentucky's calculation of the CEC program subscription fee, energy credit (for low-income participants and other participants), and sharing of savings.

d. State whether Duke Kentucky believes the CEC program should have a different energy or capacity rate than qualifying facilities (QFs). Provide support for the response with any necessary documentation or calculations.

e. Confirm whether Duke Kentucky's QF rates are reflected in the CEC value stack. If not, explain why not. If yes, explain and provide calculations and all workpapers in Excel spreadsheet format with all formulas, rows, and columns unprotected and fully accessible and with all links intact.

RESPONSE:

a. The Company recognizes that the Commission has established these components as relevant values to be addressed in a revised net metering filing and therefore the Company will address each of these components in the net metering filing. The CEC program values were derived looking at the CEC program characteristics specifically. Similarly, the Company will analyze net metering under a program specific lens for the same value categories. The CEC program would likely have different values compared to net metering within the same categories of value, due to resource configuration and utility control of the asset.

b. As referenced on page 13 of the Direct Testimony of Paul L. Halstead, the input assumptions for PLH-2 are generally consistent with the fixed-tilt solar project characteristics contained within Generic Unit Summary (GUS) information used for Integrated Resource Planning (IRP) analysis. Since the examples provided in PLH-2 and PLH-3 were intended to be generic examples and not specific to a particular project, specific project breakdowns of these inputs are not available. All formula, rows and columns within PLH-2 and PLH-3 are intact with one exception. The Program Revenue Requirements on tab "Rev RQ_Benefits" provided in Column E of Confidential Attachment PLH-3 are the same annual values calculated and displayed on Row 50 of the tab "Revenue Requirements" in Confidential Attachment PLH-2.

c. All formulas are contained within Confidential Attachment PLH-3, and the derivations of the program subscription fee, energy credit and sharing of savings for the generic example provided are described in the Direct Testimony of Paul L. Halstead on pages 12-13, and 16.

d. Yes. They should be different. The Company offers cogeneration tariffs with capacity and energy values approved by the Commission consistent with the Commission's interpretation of PURPA provisions. QF contracts contemplate short term, as available agreements and may not be configured or under utility control in a manner that meets all categories of value or provides the same level of value. Therefore, the Company's cogeneration tariffs provide LMP for the energy value at the time a QF provides the energy and a near-term oriented capacity value for the amount of capacity the QF can provide. In contrast, the CEC program uses a long-term, IRP based analysis to evaluate the reduction in capacity and energy cost from the Company owned solar addition.

e. The Company's QF rates provide values for energy and capacity. Those two components are included in the representation of the CEC value stack. However, the values are not the same due to differences in the analytical timing, resource configuration, utility control and the method used to calculate the values.

PERSON RESPONSIBLE: Bruce L. Sailers – a.
Paul L. Halstead – a. thru e.