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PUC DOCKET NO. 52353

APPLICATION OF RAYBURN	§	BEFORE THE
COUNTRY ELECTRIC	§	
COOPERATIVE, INC. TO CHANGE	§	PUBLIC UTILITY COMMISSION
WHOLESALE TRANSMISSION	§	
SERVICE RATES	§	OF TEXAS

SUPPLEMENTAL TESTIMONY ON REMAND

OF

JOHN SIMPSEN

ON BEHALF OF

RAYBURN COUNTRY ELECTRIC COOPERATIVE, INC.

SEPTEMBER 1, 2022

PUC DOCKET NO. 52353

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COOPERATIVE, INC. TO CHANGE	**§**	**PUBLIC UTILITY COMMISSION**
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SUPPLEMENTAL TESTIMONY ON REMAND OF JOHN SIMPSEN

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SUPPLEMENTAL TESTIMONY ON REMAND OF JOHN SIMPSEN

I. BACKGROUND

Q. Please state your name and business address.

A. My name is John Simpsen. My business address is 5555 North Grand Boulevard, Oklahoma City, Oklahoma 73112-5507.

Q. By whom are you employed?

A. I am employed as a Senior Consultant by C. H. Guernsey & Company, Engineers ● Architects ● Consultants, Oklahoma City, Oklahoma. I primarily evaluate and prepare annual transmission revenue requirements for transmission owners in Regional Transmission Organizations and Independent System Operators. I also conduct cost of service studies and electric rates for wholesale and retail electric cooperatives. Rayburn Country Electric Cooperative, Inc. ("Rayburn") hired Guernsey to assist in preparing and presenting its Application to Change Wholesale Transmission Service Rates ("Application"), which is pending in this docket.

Q. Are you the same John Simpsen that provided direct testimony on behalf of Rayburn in this docket?

A. Yes. My direct testimony was filed with Rayburn's Application on July 26, 2021. My testimony in support of settlement was filed on February 10, 2022.

Q. What is the purpose of your supplemental testimony?

A. At the open meeting on August 4, 2022, the Public Utility Commission of Texas ("PUCT" or "Commission") requested additional information regarding Rayburn's debt service coverage ("DSC") ratio and remanded this proceeding to docket management. In the Order Remanding Proceeding to Docket Management, also dated August 4, 2022, the Commission stated "the evidentiary record does not support the use of a debt-service-coverage ratio greater than the 1.20 debt-service-coverage ratio required by the debt covenants in evidence," and directed the parties to file and seek admission of evidence and testimony supporting a reasonable DSC ratio that will result in a just and reasonable return on transmission rate base. In response to this order, my testimony addresses the following:

- Requirements in the Transmission Cost of Service Rate Filing Package for Non-Investor Owned Transmission Service Providers in the Electric Reliability Council of Texas ("Non-IOU TCOS RFP") pertaining to rate of return and DSC;[1]
- The mandatory presumption of reasonableness that is set out in the Non-IOU TCOS RFP with respect to additional coverage above an applicant's debt service requirements;
- How Rayburn's DSC and return compares to other non-IOUs; and
- The reasonableness of Rayburn's DSC ratio of 1.70, and the resulting rate of return of 11.08%.

Q. Are you sponsoring any exhibits or schedules in support of your supplemental testimony?

A. Yes, I sponsor Exhibit JS-R1 – Moody's Investors Service, Rating Methodology, US Electric Generation & Transmission Cooperatives Methodology (Nov. 22, 2021).

II. COMMISSION RULES ON DEBT SERVICE COVERAGE

Q. What is debt service coverage?

A. Debt service coverage ("DSC") is a measure of annual revenues in excess of operations and maintenance ("O&M") expenses that are available to meet total system principal and interest payments and is expressed as a ratio. For example, a DSC ratio of 1.70 reflects that a utility, after paying its O&M costs, has sufficient annual revenue to meet its principal and interest payments, plus additional funds of 70% above the principal and interest payments

[1] *Modification of Rate Filing Package for Transmission Rates*, Project No. 21276, Transmission Cost of Service Rate Filing Package for Non-Investor Owned Transmission Service Providers in the Electric Reliability Council of Texas (Dec. 16, 1999).

to satisfy other cash requirements, such as capital investment needs, funding cash reserves, or managing temporary shortfalls. A DSC ratio of 1.0 indicates that net operating income is only sufficient to cover annual debt payments and the utility is nearing negative cash flow and possible default. Negative cash flow would be a DSC ratio of less than 1.0. A DSC ratio too close to 1.0 typically means the entity is vulnerable and even a minimal decline in cash flow could render the entity unable to service its debt.

Q. Do lenders typically require certain DSC levels of borrowers?

A. Yes. Typically, an electric cooperative is contractually required in debt covenants to maintain a certain DSC level, and if it does not maintain that DSC level, the cooperative is in default of the debt covenant. The DSC shows the lender, and other investors, that the utility has enough income to pay its debts. It is an indicator of financial health and stability. Lenders routinely assess a borrower's DSC before making a loan.

Q. Please describe the Commission's rules that apply to debt service coverage and calculating rate of return.

A. The Commission's rules, at 16 Tex. Admin. Code ("TAC") § 25.192(c), allow a municipally owned utility ("MOU"), river authority, and electric cooperative to use the cash flow method or other reasonable alternative method to determine the annual transmission revenue requirement, including the return element of the revenue requirement.[2] The rule adds:

> For municipally owned utilities, river authorities, and electric cooperatives, the return may be determined based on the TSP's actual debt service and a reasonable coverage ratio. In determining a reasonable coverage ratio, the commission will consider the coverage ratios required in the TSP's bond indentures or ordinances and the most recent rate action of the rate-setting authority for the TSP.[3]

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[2] 16 TAC § 25.192(c)(2).
[3] 16 TAC § 25.192(c)(3).

The Non-IOU TCOS RFP further qualifies and provides specific instructions on the methods of calculating rate of return, including the DSC method:

> **SCHEDULE C: RATE OF RETURN, DEBT SERVICE COVERAGE, CASH FLOW, OR TIMES INTEREST EARNED RATIO**
>
> The determination of final revenue requirements for a municipal utility, river authority, power agency, or electric cooperative may be based on any of the following methods at the election of the filing TSP.
>
> * * *
>
> Schedule C-2: Debt Service Coverage (DSC) Method:
> A return based on the TSP's debt service expenses as of the end of the Historic Year, and the debt service coverage levels stated in the TSP's most recently issued bond and debt covenants plus additional coverage of 0.25 for municipal utilities and river authorities shall be presumed reasonable. To the extent the utility can show that short-term debt has been utilized in a cost-effective manner as a reasonable alternative to long-term financing, its principal and interest and an additional coverage of 0.25 may be included in calculating the return. The return for short-term debt shall not include the coverage that is specified in the bond and debt covenants unless the covenants include short-term debt service in the denominator of the DSC ratio that is used to calculate default on the debt. To the extent there are no minimum debt service coverage requirements in the TSP's bond resolutions, the Board of Director's policy, with respect to coverage, shall be considered. At the option of the TSP, the return or debt service coverage approved by a municipality's or a river authority's ratemaking authority, within three years of the TCOS, filing may be used. The TSP shall justify the use of any other debt service coverage, and shall specify the reasonable circumstances that support the use of different debt service coverage.
>
> The Texas Municipal Power Agency or its successor in interest may, at its option, use the rate of return method for calculating its transmission cost of service. If the rate of return method is used, the return component for the transmission cost of service revenue requirement shall be sufficient to meet the transmission function's pro rata share of levelized debt service and debt service coverage ratio (1.50) and other annual debt obligations; provided, however, that the total levelized debt service may not exceed the total debt service under the current payment schedule. Any additional revenue generated by the methodology described in this subsection shall be applied to reduce the agency's outstanding indebtedness.
>
> An electric cooperative may, ***at its option***, use the debt service coverage method for calculating its transmission cost of service. ***The debt service coverage levels stated in the cooperative's most recent debt covenants plus additional coverage of 0.50 shall be presumed reasonable***. To the extent that short-term debt is included in the calculation of these debt service

> coverage level covenants, it may be included in the debt service coverage used to calculate the transmission cost of service. To the extent there are no minimum debt service coverage requirements in the cooperative's debt covenants, the Board of Director's policy, with respect to coverage, shall be considered. At the option of the TSP, debt service coverage, based on rates approved by a cooperative's ratemaking authority, within three years of the TCOS filing may be used. ***The cooperative shall justify the use of any other debt service coverage, and shall specify the reasonable circumstances that support the use of different debt service coverage***.[4]

Q. Please summarize what this means for an electric cooperative.

A. An electric cooperative may, at its option, elect the DSC method for calculating rate of return. The minimum DSC ratio is calculated by adding the debt service coverage stated in the electric cooperative's most recent debt covenants plus additional coverage of 0.50. The resulting DSC "shall be" presumed reasonable. If the electric cooperative uses any other DSC, such as additional coverage of 0.60, it must justify that other DSC and specify the reasonable circumstances that support the use of a different DSC.

Q. If an electric cooperative uses the presumed reasonable additional coverage of 0.50, does it have to provide additional evidence to support that additional coverage?

A. No. According to the Commission's Non-IOU TCOS RFP, the only scenario in which an electric cooperative is required to present evidence of the reasonableness of its DSC is if the electric cooperative seeks a DSC greater than the minimum DSC (debt covenant requirement + 0.50). Otherwise, the presumption is the evidence.

Q. What language in the Non-IOU TCOS RFP leads you to this conclusion?

A. The above quoted and emphasized language. The Non-IOU TCOS RFP states, "The debt service coverage levels stated in the cooperative's most recent debt covenants plus additional coverage of 0.50 shall be presumed reasonable." I understand "shall be" to mean

[4] Non-IOU TCOS RFP at 15-16 (emphasis added).

"mandatory." If the electric cooperative uses the method and calculation specified in this sentence, the resulting DSC is reasonable. Only if the electric cooperative seeks a DSC greater than the minimum is evidence of reasonableness required, which is addressed by the following sentence in the instructions: "The cooperative shall justify the use of any other debt service coverage, and shall specify the reasonable circumstances that support the use of different debt service coverage."

Q. Is there a similar presumption of reasonableness for other non-IOUs that use the DSC method?

A. Yes, MOUs and river authorities are entitled to additional coverage of 0.25. The DSC instruction states, "the debt service coverage levels stated in the TSP's most recently issued bond and debt covenants plus additional coverage of 0.25 for municipal utilities and river authorities shall be presumed reasonable."

Q. Do you know the history of this presumed reasonable standard for non-IOUs?

A. Yes. I have reviewed the filings and comments in Project No. 21276, the project in which the Commission adopted the Non-IOU TCOS RFP in 1999.[5] The Commission held a workshop and solicited comments from stakeholders on the proposed RFP.[6] The presumption of reasonableness was actually created in 1996, when the Commission first adopted guidelines for TCOS.[7] In 1999, stakeholders filed comments debating the presumed reasonable standard, with some stakeholders arguing to remove it.[8] After the

[5] *Modification of Rate Filing Package for Transmission Rates*, Project No. 21276, Transmission Cost of Service Rate Filing Package for Non-Investor Owned Transmission Service Providers in the Electric Reliability Council of Texas (adopted Dec. 16, 1999 and filed Jan. 24, 2000).
[6] Project No. 21276, Summary of Comments and Responses to Non-IOU TCOS RFP at 1 (Jan. 24, 2000).
[7] *See* Project No. 21276, Comments of the City of Austin d/b/a Austin Energy at 2 (Nov. 15, 1999).
[8] Project No. 21276, Summary of Comments and Responses to Non-IOU TCOS RFP at 7, 9 (Jan. 24, 2000); *see also, e.g.,* Project No. 21276, Comments of Texas Industrial Energy Consumers at 5-6 (Nov. 15, 1999); Project No. 21276, Reply Comments of Texas Industrial Energy Consumers at 3 (Nov. 19, 1999).

comment process in Project No. 21276, the Commission retained the presumed reasonable DSC standard for non-IOUs, and it has persisted ever since.[9]

Q. Does the Commission treat the Non-IOU TCOS RFP instructions as binding?

A. Yes. Just a few months ago in the TCOS case involving Denton Municipal Electric ("DME"), the Commission addressed the Non-IOU TCOS RFP instructions and whether those instructions required DME to amend its application to include a depreciation study.[10] Staff and the Office of Public Utility Counsel ("OPUC") had appealed the Commission ALJ's determination that the Non-IOU TCOS RFP does not have the force of law but is better characterized as "a guidance document designed to assist regulated entities . . . because the rate-filing package was not subject to the rigors of the rulemaking process in the Administrative Procedures Act."[11] In their appeal, Staff and OPUC argued that the instructions carry the force and effect of law.[12] The Commission agreed with Staff and OPUC, and required DME to amend its application to include a depreciation study before the matter could proceed.[13] Noting that failing to follow the Non-IOU TCOS RFP causes delay and increases the expense of a proceeding, the Commission held:

> The Commission approved the rate filing package. It requires an updated depreciation study in the absence of Commission approved rates, and the Commission expects instructions in its application forms to be followed. Accordingly, the Commission grants Commission Staff's and OPUC's appeal of Order No. 4.[14]

Q. How does the decision in Docket No. 52715 apply to the DSC ratio issue in this case?

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[9] Non-IOU TCOS RFP at 15-16.

[10] *Application of Denton Municipal Electric to Change Rates for Wholesale Transmission Service*, Docket No. 52715, Order on Appeal of Order No. 4 at 1, 3 (May 12, 2022).

[11] Docket No. 52715, Order No. 4 at 3 (Jan. 31, 2022); Docket No. 52715, Commission Staff and the Office of Public Utility Counsel's Joint Appeal of Order No. 4 and Order No. 5 at 2, 10 (Mar. 4, 2022).

[12] Docket No. 52715, Commission Staff and the Office of Public Utility Counsel's Joint Appeal of Order No. 4 and Order No. 5 at 2-6 (Mar. 4, 2022).

[13] Docket No. 52715, Order on Appeal of Order No. 4 at 2-3.

[14] Docket No. 52715, Order on Appeal of Order No. 4 at 3.

A. The Commission expects its instructions and forms to be followed. This makes sense. If the Commission's rules adopted in the Non-IOU TCOS RFP could be changed on a case-by-case basis without notice and comment, or if any party could ignore them without showing good cause, there would be no regulatory certainty and administrative inefficiency. Discovery, remands, and delays would likely proliferate. As applied to this case, the Non-IOU TCOS RFP prescribes instructions for the DSC method of calculating return, including the presumed reasonable standard for determining the DSC ratio. This instruction, including the presumed reasonable standard, provides regulatory certainty and administrative efficiency. Applicants prepare their rate filing packages in reliance on these instructions, which the Commission has made clear must be followed. Rayburn followed the instructions in this case.

Q. Has the Commission previously approved non-IOU TCOS applications that implemented the presumed reasonable DSC?

A. Yes. I reviewed a number of non-IOU TCOS applications approved over the last 13 years. I identified 12 non-IOU TCOS cases during this period in which the non-IOU used the DSC method to calculate rate of return.[15] In all but one of those cases, the non-IOUs (either

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[15] *See, e.g.*, *Application of GEUS to Change rates for Wholesale Transmission Service*, Docket No. 51556, Application, Direct Testimony & Attachments of Jill A. Scheupbach at 11-14 (Nov. 24, 2020); Order at FOF 16 (Sept. 29, 2021); *Application of the City of Lubbock, By and Through Lubbock Power & Light, For Authority to Establish Initial Wholesale Transmission Rates and Tariffs*, Docket No. 51100, Application, Direct Testimony of Tony Georgis, P.E. at 9-12 (Aug. 18, 2020), Order at FOF 35-36 (Aug. 3, 2021); *Application of East Texas Electric Cooperative, Inc. to Change Wholesale Transmission Service Rates*, Docket No. 50295, Application, Direct Testimony of Alfred W. Busbee at 16 & Schedule C-2 (Nov. 26, 2019), Order (Jan. 14, 2021); *Application of Fayette Electric Cooperative, Inc. to Change Rates for Wholesale Transmission Service*, Docket No. 50204, Application, Direct Testimony of Bob Beam at 5 (Nov. 20, 2019), Order at FOFs 22-24 (Sept. 24, 2020); *Application of Golden Spread Electric Cooperative, Inc. for Authority to Change Transmission Cost of Service and Wholesale Transmission Rates*, Docket No. 48500, Application, Direct Testimony of Francesca Winter at 12 (June 29, 2018), Order at FOFs 33-34 (Apr. 4, 2019); *Application of Rayburn Country Electric Cooperative, Inc. for Authority to Change Transmission Cost of Service and Wholesale Transmission Rates*, Docket No. 47370, Application, Direct Testimony of David A. Naylor, PE at 10-11 (June 30, 2017), Order at FOF 22 (Dec. 14, 2017); *Application of San Bernard Electric Cooperative, Inc. for Approval of Transmission Cost of Service and Wholesale Transmission Rates*, Docket No. 44897, Application, Direct Testimony of Judy K. Lambert at 7 (June 30, 2015), Order (Nov. 6, 2015); *Application of Brazos Electric Power Cooperative,*

an MOU, river authority, or electric cooperative) established their DSC ratios based on their respective debt covenant obligations and added the presumed reasonable additional coverage authorized by the Non-IOU TCOS RFP (either 0.25 or 0.50).[16] The Commission approved all of them.[17]

The outlier involved Lubbock Power & Light ("LP&L), which sought additional coverage above the minimum presumed reasonable DSC for MOUs.[18] LP&L's debt covenant requirement was 1.25, and it sought to add 0.50 of additional coverage to its DSC, which is more than the presumed reasonable 0.25 for MOUs.[19] As a result, LP&L presented testimony to support the requested DSC that was greater than the minimum authorized by the Non-IOU TCOS RFP.[20] LP&L's justification for the additional coverage was that the presumed reasonable 0.25 did not allow LP&L to adequately cover its cash obligations, including specifically the hold harmless payment associated with its transition to ERCOT approved in Docket No. 47576.[21] The Commission approved the requested additional coverage above the minimum DSC.[22]

Inc. for Authority to Change Transmission Cost of Service, Docket No. 44754, Application, Direct Testimony of Khaki J. Bordovsky at 15-17 (July 9, 2015), Order at FOFs 15-16 (Oct. 8, 2015); *Application of City of Garland to Change Rates for Wholesale Transmission Service*, Docket No. 43347, Application, Direct Testimony of Jack E. Stowe at 13-14 (Sept. 23, 2014), Order (Feb 18, 2015); *Application of South Texas Electric Cooperative, Inc. to Change Rates for Wholesale Transmission Service*, Docket No. 41527, Application, Direct Testimony of Daniel Walker at 57-58 (May 28, 2013), Order (Sept. 16, 2013); *Application of LCRA Transmission Services Corporation to Change Rates*, Docket No. 39891, Application, Direct Testimony of Craig Sloan at 34-36 (Nov. 4, 2011), Order at FOF 17 (Mar. 8, 2012); *Application of Grayson-Collin Electric Cooperative, Inc. for Approval of Transmission Cost of Service and Wholesale Transmission Rates*, Docket No. 36984, Application, Direct Testimony of David A. Naylor, PE at 6-7 (May 12, 2009), Order (Aug. 27, 2009).

[16] *Id.*

[17] *Id.*

[18] Docket No. 51100, Application, Direct Testimony of Tony Georgis, P.E. at 9-12.

[19] *Id.*; *see also* Non-IOU TCOS RFP at 15-16.

[20] Docket No. 51100, Application, Direct Testimony of Tony Georgis, P.E. at 9-12.

[21] Docket No. 51100, Direct Testimony of Tony Georgis, P.E. at 11-12 (citing *Application of the City of Lubbock Through Lubbock Power & Light for Authority to Connect a Portion of Its System with the Electric Reliability Council of Texas*, Docket No. 47576, Order (Mar. 15, 2018)).

[22] Docket No. 51100, Order at FOF 35-36.

III. RAYBURN'S DSC CALCULATION

Q. Please describe the method Rayburn used to calculate return on rate base.

A. In accordance with 16 TAC § 25.192(c)(3) and the Non-IOU TCOS RFP Instructions, Rayburn calculated its required return based on the DSC method found in Schedule C-2. Rayburn's most recent debt covenant requires a DSC of 1.20. Excerpts of this debt covenant requirement were attached to my direct testimony as Exhibit JS-3(CONF) and admitted into evidence. Consistent with the Non-IOU TCOS RFP, Rayburn added additional coverage of 0.50, resulting in a presumed reasonable DSC of 1.70. As shown on Schedule C-2, Rayburn used the 1.70 DSC to calculate a rate of return of 11.0826%.

Q. Why did Rayburn elect to use the DSC method to determine its return?

A. First, Rayburn's primary lender is the National Rural Utilities Cooperative Finance Corporation ("CFC"). CFC uses DSC to evaluate loans, and requires its borrowers to maintain a certain DSC level as of the end of each fiscal year.[23] The debt covenant in Rayburn's loan agreement states a DSC level that Rayburn is required to maintain to avoid default.[24] Rayburn uses the DSC method to establish its TCOS and wholesale transmission rates to ensure that the ratemaking is in alignment with this debt covenant and capital market requirement. Financial performance as demonstrated by DSC is a key indicator of Rayburn's ability to pay debt service and, therefore, to attract the capital it needs to provide service to its members.

Second, DSC accounts for Rayburn's need to repay both the principal and interest due on its debt obligations, as opposed to other methods allowed such as TIER, which focus on the cooperative's ability to repay its interest earned and not principal.

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[23] *See* Direct Testimony of John Simpsen, Ex. JS-3 (CONF) at 2.
[24] *See* Direct Testimony of John Simpsen, Ex. JS-3 (CONF) at 2.

Third, Rayburn's current debt service obligations combined with anticipated near-term future debt-service requirements are significant and require minimum cash requirements for principal and interest repayments that are best calculated by DSC. Rayburn is in a high-growth area of the State in the heart of the bulk electric system, with substantial projects having already been completed after the test year and projected in the near-term. As shown in the Application, between May 2017, the end of Rayburn's last test year, and December 2020, the end of the test year in this docket, Rayburn invested approximately $134,814,260 in gross transmission plant. Since the test year ending December 2020 in this case, Rayburn has already invested another $54,290,580 in 2021 and projects another $25,648,560 by the end of this year. In 2023, Rayburn projects another $75,000,000 in gross transmission investment, including investment in a transmission line project approved in Docket No. 50812[25] and a number of new generation interconnections. Table 1 shows the historical and projected gross, unadjusted transmission plant investment.

Table 1 – Historical and Projected Transmission Plant Investment

Description	Dec-18	Dec-19	Dec-20	Dec-21	Dec-22	Dec-23
Transmission – Land	17,067,640	20,539,740	21,967,600	28,319,460	33,464,060	48,464,060
Transmission – Other	105,761,410	176,185,680	189,821,860	237,760,580	258,264,550	318,264,550
Total Transmission Plant	122,829,050	196,752,420	211,789,470	266,080,050	291,728,610	398,728,610
Annual Increase	45,857,840	73,896,380	15,064,040	54,290,580	25,648,560	75,000,000

In addition, pursuant to the order in Docket No. 48400, Rayburn is making a hold harmless payment of $4.5 million per year through 2024, as a result of its integration of

[25] *Application of Rayburn Country Electric Cooperative, Inc. to Amend its Certificate of Convenience and Necessity for the New Hope 138-kV Transmission Line in Collin County*, Docket No. 50812, Order (July 20, 2021).

certain load and facilities into ERCOT.[26] This expense is not included in TCOS, but rather is implemented as a wholesale transmission service credit rider, which affects Rayburn's cash position. This is the same type of hold harmless payment that LP&L used to justify its additional coverage above the presumed reasonable standard in Docket No. 51100, which the Commission approved.[27] Despite this precedent, Rayburn has not sought to increase its DSC above 1.70, but the hold harmless payment further justifies Rayburn's use of the DSC method and the presumed reasonable additional coverage of 0.50.

Fourth, it should be understood that Rayburn is a not-for-profit electric cooperative. It operates without profit to its members.[28] In particular, the Electric Cooperative Corporation Act requires as follows:

> Sec. 161.059. NONPROFIT OPERATION. (a) An electric cooperative shall operate without profit to its members.
>
> (b) The rates, fees, rents, and other charges for electric energy and other facilities, supplies, equipment, or services furnished by the cooperative must be sufficient at all times to:
>
> (1) pay all operating and maintenance expenses necessary or desirable for the prudent conduct of its business;
>
> (2) pay the principal of and interest on the obligations issued or assumed by the cooperative in performing the purpose for which the cooperative was organized; and
>
> (3) create reserves.
>
> (c) The cooperative shall devote its revenues:
>
> (1) first to the payment of operating and maintenance expenses and the principal and interest on outstanding obligations; and

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[26] *Joint Application of Rayburn Country Electric Cooperative, Inc. and Lone Star Transmission, LLC to Transfer Load to ERCOT, for Sale of Transmission Facilities, and Transfer of Certificate Rights in Henderson and Van Zandt Counties,* Docket No. 48400, Final Order at Order. Para. 9 (Mar. 13, 2019).
[27] Docket No. 51100, Application, Direct Testimony of Tony Georgis, P.E. at 9-12; Docket No. 51100, Order at FOFs 35-36.
[28] TEX. UTIL. CODE § 161.059.

> (2) then to the reserves prescribed by the board for improvement, new construction, depreciation, and contingencies.
>
> (d) The cooperative shall periodically return revenues not required for the purposes prescribed by Subsection (c) to the members in proportion to the amount of business done with each member during the applicable period. The cooperative may return revenues:
>
> (1) in cash, by abatement of current charges for electric energy, or in another manner determined by the board; or
>
> (2) through a general rate reduction to members.[29]

Accordingly, Rayburn must pay its expenses and debt obligations, create reserves for prudent operation, and periodically return margin revenues to members, typically through rate reduction. Rayburn is not influenced by profit generating motives that can sometimes influence the decisions of an IOU. Rayburn's source of funding is revenues from electric rates and short- and long-term financing. Using the DSC method allows Rayburn to earn a return on rate base that satisfies its debt covenants, plus additional coverage to achieve a margin above debt obligations to ensure it can operate prudently pursuant to Tex. Util. Code § 161.059. Accordingly, the DSC method is an appropriate method by which to evaluate its financial integrity and ensure sufficient return.

Q. Please explain the steps used to calculate return using the DSC method.

A. Calculating the rate of return is a straight-forward formula outlined in the Non-IOU TCOS RFP. First, the debt service requirement (interest and principal) is calculated in dollars ($30,928,796 for Rayburn).[30] Second, the debt service is multiplied by the required DSC ratio plus 0.50 (1.20 + 0.50 = 1.70), resulting in the debt service coverage amount in dollars ($52,578,953 for Rayburn).[31] Third, Rayburn's depreciation and interest income are

[29] TEX. UTIL. CODE § 161.059.
[30] Rayburn, Application at 134 (Schedule C-2).
[31] Rayburn, Application at 134 (Schedule C-2).

subtracted from the debt service coverage amount, resulting in the net return expressed in dollars ($52,578,953 - $15,654,515 = $36,924,438 net return for Rayburn).[32] Fourth, the return is divided by the total rate-base balance calculated in Schedule B of the Non-IOU TCOS RFP ($36,924,438 / $333,174,015 for Rayburn) to calculate a percentage return on rate base (11.0826% for Rayburn).[33] Fifth, the return on rate base percentage is multiplied by the transmission rate base from Schedule B, resulting in the transmission return as a dollar amount ($19,584,182).[34] Finally, the transmission return is included on Schedule A as part of the transmission revenue requirement.[35]

Q. Did you calculate the return correctly?

A. Yes, I followed the steps above, as shown on Schedule C-2, Schedule B, and Schedule A.

Q. How does Rayburn's DSC ratio, and resulting rate of return, compare to its last full TCOS case?

A. In Docket No. 47370, the Commission approved a DSC ratio of 1.70 and a rate of return of 12.11%. In this case, Rayburn seeks the same DSC ratio of 1.70, resulting in a 11.08% rate of return, which is a decrease from its currently-authorized return.

Q. How does Rayburn's return compare to other non-IOUs.

A. Given that the rate of return is the result of the methodology mandated in the non-IOU TCOS RFP, non-IOU returns based on the DSC method vary widely, ranging from 5.46% to 14.27%.[36] This variation is a function of the inputs into the formula, including debt service requirement, depreciation, interest income, and rate base. The formula results in a percentage return that shows the respective non-IOU's cash needs compared to rate base.

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[32] Rayburn, Application at 134 (Schedule C-2).
[33] Rayburn, Application at 134 (Schedule C-2).
[34] Rayburn, Application at 118 (Schedule B).
[35] Rayburn, Application at 117 (Schedule A).
[36] See note 18, *supra*.

Q. Should Rayburn's return be compared to an IOUs return?

A. No. Rayburn's calculated return of 11.08% is a mathematical result of the DSC method. Comparing that result with an approved IOU return is not appropriate. As I explained above, electric cooperatives like Rayburn are not-for-profits. They are not motivated to recover a higher return than necessary because the result would be higher costs to its members, who are the owners. Rayburn's sources of capital are from revenues on electric rates and long- and short-term debt pledged to system revenues. Rayburn does not issue stock to third-party investors and is not subject to return on equity metrics commonly used to determine an IOU's weighted average cost of capital calculations. Rayburn also does not pay federal income taxes and therefore those taxes are not included as an operating expense like they are for IOUs. The two are not comparable.

Q. Did Rayburn seek any additional coverage above the minimum 1.70 DSC, or any adjustments to its return calculation?

A. No.

IV. ADDITIONAL COVERAGE OF 0.50 IS REASONABLE

Q. Why is Rayburn's DSC of 1.70, which includes the additional coverage of 0.50, reasonable and appropriate in this case?

A. It is reasonable and appropriate for several reasons, which I summarize as follows:

- Additional coverage of 0.50 is presumed reasonable under the Non-IOU TCOS RFP, as I explained above.
- Additional coverage of 0.50 is necessary to ensure a reasonable margin so that Rayburn can operate as a financially prudent utility.
- Additional coverage of 0.50 is necessary to assure confidence in Rayburn's financial soundness so that it may continue to access financing on favorable terms.
- Additional coverage of 0.50 is reasonable given Rayburn's future financing needs.

- Additional coverage of 0.50 matches the additional coverage approved for other electric cooperatives.

Q. Please elaborate on why Rayburn needs to earn a margin above its debt covenant obligations?

A. The general concept is that a utility must have the opportunity to earn a reasonable rate of return that allows it to assure its financial integrity so it can maintain its credit standing and attract additional capital, and also achieve margins to operate as a prudent utility. Prudent financial planning requires a utility to maintain debt service coverage targets higher than the annual debt service payments and the coverage levels required by debt covenants. Higher coverage targets also help to reduce future borrowing needs by partially funding capital expenditures.

In this case, additional coverage of 0.50 is necessary to ensure a reasonable margin so that Rayburn can operate as a financially prudent utility. Rayburn's actual debt covenant requires a 1.20 DSC ratio. But Rayburn must achieve return beyond merely the principal and interest expense for borrowing to remain financially sound. Rayburn must earn a margin above its debt obligation so that it can fund construction of improvements, protect against unexpected occurrences, and deal with temporary shortfalls. The additional coverage of 0.50 also allows Rayburn to manage regulatory lag. Rayburn's TCOS in this proceeding is based on test-year financials that were already stale when the rate case was filed, and the revised rate will already be out of date when put in place almost two years after the test year ending December 31, 2020. Allowing for additional coverage of 0.50 above Rayburn's debt covenant obligation provides essential margin for utility operations, given that the rate is based on two-year old data and the coverage ratio erodes with time due to the nature of utility operations and depreciation of aging plant. The additional coverage of 0.50 ensures that Rayburn will not default on its loan covenants, can earn a return that allows it to set equity objectives, and can maintain adequate margins over time as the coverage ratio erodes.

Q. Explain how the DSC ratio affects Rayburn's credit quality and ability to attract capital?

A. DSC is an indicator of financial integrity and credit worthiness, or credit quality. Better credit quality enables Rayburn to attract more favorable credit terms. The ability to attract capital at a reasonable cost enables Rayburn to build and maintain plant and to meet its service obligations. Thus, Rayburn's continued access to financial markets is dependent on maintaining its credit quality.

Rayburn is currently rated investment grade Baa3/Stable by Moody's and BBB-/Stable by Standard and Poor's. These ratings are based in part on Rayburn's current approved DSC ratio of 1.70, approved in Docket No. 47370 on December 14, 2017. Prior to Winter Storm Uri, Rayburn was rated A- by Standard and Poor's. Following the storm, that rating dropped to CCC, but Rayburn has worked to get it back to investment grade BBB-/Stable. Rayburn's goal is to return to A-, because that rating allows for more favorable credit terms. Rayburn was not rated by Moody's prior to Winter Storm Uri.

A credit rating is a measure of credit risk. Lenders have choices regarding how they deploy funds, and a borrower's credit quality is a primary driver in a lender's decision to allocate available funds. With its current Baa3/Stable and BBB-/Stable ratings, Rayburn is able to qualify with a fair number of lenders and achieve relatively favorable loan terms in a competitive market for capital. Continuing to improve its credit rating will expand the number of willing lenders and improve loan terms and cost of capital. A quality credit rating, and hence lower cost of capital, benefits Rayburn's member systems, transmission service customers who pay its wholesale transmission service rate, and ultimately all ERCOT ratepayers. Maintaining a strong financial profile is a key priority for Rayburn so that it can continue to build safe and reliable transmission facilities on favorable financing terms at the lowest possible cost of capital.

A reduction of Rayburn's current DSC ratio of 1.70 would be a negative hit to its credit quality, could limit its ability to access credit on favorable terms, and would be counter to the interests of ratepayers. A credit downgrade would likely increase debt cost and cause lenders to impose constraining covenants and requirements. Any debt issued when ratings are lower would carry higher costs for the life of the debt.

Ratings agencies rely heavily on DSC in making ratings determinations. DSC provides security to lenders for the financial risks associated with lending money. Moody's provides ratings guidance for determining how it rates electric generation and transmission ("G&T") cooperatives like Rayburn. A large factor in establishing the rating of a G&T is its DSC.[37] For an Aa investment grade, Moody's looks for a DSC in the range of 1.40 – 1.90. Rayburn's DSC ratio of 1.70 is in line with this range, but a DSC ratio lower than this would make it more difficult for Rayburn to improve its rating. Moreover, Rayburn's current Baa3 rating by Moody's is based on Rayburn's current 1.70 DSC ratio, thus that 1.70 DSC ratio is important for Rayburn to not only improve, but retain, its current rating. In this manner, the additional coverage of 0.50 supports Rayburn's credit rating and access to financing on favorable terms, which is to the benefit of ratepayers. I believe a 1.70 DSC ratio earned on a consistent basis represents the financial performance needed for Rayburn to maintain its credit rating and is the level expected by rating agencies and its lenders.

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[37] *See* Moody's Investors Service, Rating Methodology, US Electric Generation & Transmission Cooperatives Methodology at 12-13 (Nov. 22, 2021), attached hereto as Exhibit JS-R1.

Q. Explain how Rayburn's future financing needs relate to the DSC ratio?

A. As I explained above, Rayburn expects to invest approximately $154 million in transmission plant by December 2023 through a combination of short-term and long-term financing. This affects not only Rayburn's future cash position, but emphasizes the importance of its ability to attract future financing. As Rayburn secures financing for these future projects, its lenders will evaluate its ability to repay principal and interest. One of the key factors in determining whether to allocate capital to Rayburn will be the DSC it expects to earn on those projects, which directly correlates to its ability to repay the loans and service its lines of credit. Thus, maintaining additional coverage of 0.50 is reasonable given Rayburn's future financing needs.

Q. How does Rayburn's additional coverage of 0.50 compare to other non-IOUs?

A. Rayburn's requested additional coverage of 0.50 matches the additional coverage approved for other electric cooperatives, including South Texas Electric Cooperative, Brazos Electric Power Cooperative, East Texas Electric Cooperative, Golden Spread Electric Cooperative, Fayette Electric Cooperative, Grayson-Collin Electric Cooperative, and San Bernard Electric Cooperative.[38] Similarly, the Commission has approved the presumed reasonable 0.25 of additional coverage for MOU's and river authorities that use the DSC method, including: Garland Power & Light, Greenville Electric Utility System, and LCRA.[39] And in the LP&L case discussed above, the Commission approved even more additional coverage.[40]

Q. In your opinion, is Rayburn's DSC of 1.70, which includes the additional coverage of 0.50, reasonable and appropriate?

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[38] *See* dockets cited at note 15.
[39] *See* dockets cited at note 15.
[40] Docket No. 51100, Order at FOF 35-36.

A. Yes. Based on the level of debt service and the fiscal needs of the cooperative, the presumed reasonable 1.70 DSC ratio is appropriate. As explained above, the 1.70 DSC ratio allows Rayburn to earn a reasonable margin above its debt obligations necessary to operate the cooperative, remain financially sound, and maintain access to financing on favorable terms. The additional coverage of 0.50 also matches the additional coverage the Commission has approved for other electric cooperatives.

Q. In your opinion, does the DSC ratio of 1.70 result in a just and reasonable return on transmission rate base?

A. Yes, as I described above, the fall out rate of return using the 1.70 DSC ratio is 11.08%. The rate of return was calculated properly and results in a reasonable return on transmission rate base in the amount of $19,584,182.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Rayburn properly calculated its DSC and resulting return consistent with the Non-IOU TCOS RFP. Rayburn's debt covenant requires a 1.20 DSC ratio. The additional coverage of 0.50 is presumed reasonable and, in any event, is reasonable and appropriate. The additional coverage is consistent with the additional coverage authorized for other electric cooperatives and allows Rayburn to cover its debt obligations, earn sufficient margin to operate the cooperative, and maintain its credit rating. The resulting return was calculated properly and results in a reasonable return of 11.08%, a decrease from Rayburn's currently-authorized return.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

STATE OF OKLAHOMA §
§
COUNTY OF OKLAHOMA §

BEFORE ME, the undersigned authority, on this day personally appeared John Simpsen, who, having been placed under oath by me, did depose as follows:

"My name is John Simpsen. I am of legal age and a resident of the State of Oklahoma. The foregoing testimony, attached exhibits, and opinions offered by me are accurate, true, and correct to the best of my knowledge and belief."

John Simpsen

SUBSCRIBED AND SWORN TO BEFORE ME by the said John Simpsen this 31st day of August, 2022.

AMBER NELSON NOTARY # 20012136 EXP. 10/01/24 PUBLIC STATE OF OKLAHOMA

Notary Public, State of Oklahoma

MOODY'S
INVESTORS SERVICE

RATING
METHODOLOGY

US Electric Generation & Transmission Cooperatives Methodology

This rating methodology replaces "US Electric Generation & Transmission Cooperatives", last revised on August 10, 2018. We have eliminated an appendix that described the US electric generation and transmission cooperatives industry overview, which is described in the "About the Rated Universe" section below. We have also made editorial changes to enhance readability. These updates do not change our methodological approach.

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Summary

This rating methodology explains our approach to assessing credit risk in the U.S. electric generation & transmission cooperative sector (G&T co-ops). This methodology is intended as a reference tool to use when evaluating credit profiles within this sector, helping issuers, investors, and other interested market participants understand how key qualitative and quantitative risk characteristics are likely to affect rating outcomes. This methodology 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 typically most important for ratings in this sector.

This report includes discussion of the five factors and sub-factors included in the scorecard. The purpose of the scorecard is to provide a reference tool that can be used to approximate credit profiles within the U.S. electric generation & transmission cooperative sector. The scorecard provides summarized guidance for the factors that are generally most important in assigning ratings to these entities. The scorecard is a summary, and as such, 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 significantly. The scorecard-indicated outcome will not match the actual rating of each entity in every case.

The scorecard contains five factors that are important in our assessment for ratings in the U.S. electric generation & transmission cooperative sector.

1. Long-Term Wholesale Power Supply Contracts/Regulatory Status

2. Rate Flexibility

3. Member/Owner Profile

4. Financial Metrics

5. Size

Certain factors also encompass a number of sub-factors or metrics that we explain in detail. An issuer's scoring on a particular scorecard factor sometimes will not match its overall rating.

We note that our rating analysis in this sector covers factors that are common across all industries as well as factors that can be meaningful on a company or sector-specific basis. Our ratings incorporate qualitative considerations and factors that do not lend themselves to a transparent presentation in a scorecard format. The scorecard represents a decision to avoid greater complexity that would result in scorecard-indicated outcomes that map more closely to actual ratings, in favor of simple and more transparent presentation of the factors that are most important for ratings in this sector most of the time.

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A description of the scorecard factors

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

The Appendix shows the full scorecard.

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 use of credit estimates and country ceilings, 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.[1]

About the Rated Universe

We currently rate U.S. electric G&T cooperatives. An electric generation & transmission cooperative is a not-for-profit rural electric system whose primary function is to provide electric power on a wholesale basis to its owners. These owners are comprised of a group of distribution co-ops and in some instances, may also include other G&T co-ops. Each distribution[2] cooperative sells power on a retail basis to its customers, who are the members that own the distribution co-op.

G&T co-ops, in large part, typically maintain sound credit quality reflecting the strong contractual bonds with member owners under long-term wholesale power supply contracts, rate setting autonomy, and conservative management of their businesses by:

» using long-term supply planning to diversify their supply mix, while managing demand growth

» tightly controlling operating costs,

» increasing rates when necessary, and

» carefully attending to liquidity.

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

[2] We would apply this methodology for the distribution cooperatives with some adjustments.

G&T co-ops are similar to investor-owned utilities (IOUs) and Municipal and Public Utilities (Municipals) as they all operate in a capital-intensive industry and provide an essential service. While all three subsets of the U.S. power sector strive to provide safe and reliable electric service at the lowest possible cost, the G&T co-ops and the Municipals are not-for-profit entities, so they are not influenced by the profit generating motives that can sometimes influence strategic operating and financial decisions made by the IOUs. Revenue stability and predictability tends to be higher for both G&T co-ops and Municipals because of the rate setting autonomy that exists, whereas IOUs can experience more variability due to rate regulation that governs the rate setting process for them. Financing sources vary across the three sectors. IOUs primarily rely on the capital markets, including through issuance of common stock, whereas the Municipals fund their operations primarily through tax-exempt debt issuance in the public and private capital markets, while the G&T co-ops rely extensively on loans provided by the Rural Utilities Service (RUS), other cooperative financial institutions, and to a lesser extent, the public and private capital markets.

About This Rating Methodology

Our U.S. electric G&T cooperative rating methodology consists of the five sections listed below.

1) Identification and Discussion of the Scorecard Factors

The scorecard in this methodology focuses on five broad factors, further broken down into 14 sub-factors and their weightings.

EXHIBIT 1

Factor / Sub-Factor Weighting - U.S. Electric G&T Cooperatives

Broad Factors	Broad Factor Weighting	Sub-Factor	Sub-Factor Weighting
Wholesale Power Contracts and Regulatory Status	20%	% Member Load Served and Regulatory Status	20%
Rate Flexibility	20%	Board Involvement / Rate Adjustment Mechanism	5%
		Purchased Power / Sales (%)	5%
		New Build Capex (% of Net PP&E)	5%
		Rate Shock Exposure	5%
Member / Owner Profile	10%	Residential Sales / Total Sales	5%
		Members' Consolidated Equity / Capitalization	5%
3-Year Average G&T Financial Metrics	40%	TIER	5%
		DSC	5%
		FFO / Debt	10%
		FFO / Interest	10%
		Equity / Capitalization	10%
G&T Size	10%	MWh Sales	5%
		Net PP&E	5%
Total	**100%**		**100%**

Source: Moody's Investors Service

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These factors are critical to the analysis of U.S. Electric G&T cooperatives and, in most instances, can be benchmarked across the sector. The discussion begins with a review of each factor and an explanation of its importance to the rating.

2) Measurement or Estimation of the Scorecard Factors

We explain the measurements we use to assess performance on each of the factors and sub-factors. We explain the rationale for using specific factors and provide insights on the way these are applied in the rating decision process. Many of the sub-factors are found in or derived from the financial statements of the G&T co-ops and those of their members, while others are calculated or derived using data gathered from various sources, and observations and estimates by our analysts.

Our ratings are forward looking and incorporate our expectations of future financial and operating performance. We use both historical and projected financial results in the rating process. Historical operating results help us understand the pattern of a company's performance and how it compares to its peers. Historical data also assists us in, among other things, looking through the earnings volatility that can sometimes occur during a given year and evaluating whether projected future results are realistic.

All of the quantitative credit metric measures comprising the sub-factors in Factor 4 incorporate Moody's standard adjustments to the income statement, statement of cash flows, and balance sheet and include adjustments for certain off-balance sheet financings and certain other reclassifications in the income statement and statement of cash flows.[3]

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, or B, also called alpha categories).

4) Assumptions, Limitations and Rating Considerations that are not covered in the Scorecard

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

5) Determining the Overall Scorecard-Indicated Outcome

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

EXHIBIT 2

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

Source: Moody's Investors Service

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-average factor score. The composite weighted factor score is

3 For an explanation of our standard adjustments, please see the cross-sector methodology that describes our financial statement adjustments in the analysis of non-financial corporations.

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then mapped back to an alpha-numeric rating based on the ranges in the table below. For example, an issuer with a composite weighted factor score of 8.2 would have a Baa1 scorecard-indicated outcome.

EXHIBIT 3
Factor Numerics
Composite Outcome

Indicated Outcome	Aggregate Weighted Factor Score
Aaa	x < 1.5
Aa1	1.5 ≤ x < 2.5
Aa2	2.5 ≤ x < 3.5
Aa3	3.5 ≤ x < 4.5
A1	4.5 ≤ x < 5.5
A2	5.5 ≤ x < 6.5
A3	6.5 ≤ x < 7.5
Baa1	7.5 ≤ x < 8.5
Baa2	8.5 ≤ x < 9.5
Baa3	9.5 ≤ x < 10.5
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5

Source: Moody's Investors Service

Discussion of the Scorecard Factors

Our analysis of U.S. G&T co-ops focuses on five broad scorecard factors:

» Long-Term Wholesale Power Supply Contracts/Regulatory Status

» Rate Flexibility

» Member/Owner Profile

» Financial Metrics

» Size

Factor 1: Long-Term Wholesale Power Supply Contracts/Regulatory Status

Long-Term Wholesale Power Supply Contracts/Regulatory Status - Why it Matters

Against a myriad of credit challenges, including spending for capital projects, volatile fuel costs and persisting uncertainty surrounding environmental regulations and related costs, the strength of the wholesale power contracts and the predictable revenue stream they provide for G&T co-ops is a primary source of credit support. Because the prevalence of rate autonomy is similarly an integral credit factor linked to costs tied to the wholesale power contract, we include regulatory status of the G&T co-op and its distribution member/owners as part of Factor 1.

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Long-term wholesale power supply contracts between G&T co-ops and their members provide G&T co-ops with a high degree of assurance that costs and capital investment can be recovered from rates charged to customers. These contracts typically require the member co-ops to purchase all or virtually all of their supply requirements from the G&T co-op and generally stipulate that co-op members must pay their pro-rata portion of all of the G&T co-op's fixed and variable costs related to the generation, procurement and transmission of their respective energy needs.

G&T co-ops have more flexibility to increase rates in response to rising costs as regulatory approval is typically not required. The regulatory status/relationship with regulators is important because G&T co-ops that operate in states that have some form of regulatory authority over their rate setting activities may have more difficulty raising rates compared to peers who are not directly subject to regulatory control. Assessing a member/owner's regulatory status is also important because some are subject to rate regulation, in which case the member may be denied approval for a large rate increase, making it difficult to comply with its contractual obligations to the G&T co-op.

An unsupportive regulatory jurisdiction is a credit negative and leaves co-ops with less flexibility to raise rates if needed. In contrast, absence of regulatory control over the rate setting process is a credit positive. Most co-ops are not subject to rate regulation, and set the rates they charge their members after careful consideration of their underlying cost structure and expected demand for power. They calculate what level of revenues would be required in order to meet operating costs, minimum required interest, and debt service coverage covenants in the RUS mortgage and/or other debt indentures, while also providing some cushion of revenue and equity to protect against adverse events such as sudden increases in costs or operating difficulties with key generating plants.

Long-Term Wholesale Power Supply Contracts/Regulatory Status - How We Assess It for the Scorecard

Based on data that can be derived from various sources, we calculate the percentage of member power supply needs served under the long-term wholesale power contract(s), with consideration as to whether the contracts are all requirements or substantially all requirements in nature. An assessment of the wholesale power contract allows us to identify whether the member co-ops are required to purchase all or virtually all of their supply requirements from the G&T co-op. For G&T co-ops who are not subject to rate regulation, the indicated outcome for Factor 1 can range from Aaa to B and is largely determined by the overall percentage of member sales made under the wholesale power contracts. To receive the highest score of Aaa typically requires a legislative statute that precludes regulatory intervention in any future rate setting process.

There are states that have full regulatory jurisdiction over the level of rates that co-ops can charge their members. There are a few other states where state commissions have partial jurisdiction over G&T co-ops. Even if 100% of members' needs are met through sales under the wholesale power contracts, G&T co-ops conducting business in any of these states would typically receive an indicated outcome for Factor 1 of A at best. Where precisely the rate-regulated G&Ts score within the range of A to B depends not only on the percentage of members' needs met through sales under the wholesale power contract, but also on our consideration of how supportive of credit quality the regulatory practices are and our understanding of the type of working relationships that prevail between the co-ops and the regulators.

EXHIBIT 4

Factor 1: Long-Term Wholesale Power Supply Contracts and Regulatory Status (20%)

	Aaa	Aa	A	Baa	Ba	B
Percentage of Member Load Served under Wholesale Power Contracts and Regulatory Status	100% and G&T and its Distribution Member/Owner Cooperatives are Not Rate Regulated by State Commission; Legislative statute to preclude regulatory intervention in the future rate setting process; Very good contractual relationships	100% and G&T is Not Rate Regulated by State Commission; No legislative statute to preclude regulatory intervention in the future G&T rate setting process; Some Distribution Member/Owner Cooperatives May Be Subject to Rate Regulation by State Commission; Very Supportive Commission Practices; Very Good Regulatory/ Contractual Relationships	> 80% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated by State Commission; Very Supportive Commission Practices; Very Good Regulatory/ Contractual Relationships	> 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Moderately Supportive Commission Practices; Reasonably Good Regulatory/ Contractual Relationships	< 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Unsupportive Commission Practices; Generally Difficult Regulatory/ Contractual Relationships	< 60% and/or G&T is Rate Regulated by State Commission; Most Distribution Member/Owner Cooperatives are Rate Regulated By State Commission; Very Unsupportive Commission Practices; Often Contentious Regulatory/ Contractual Relationships

Source: Moody's Investors Service

Factor 2: Rate Flexibility

Rate Flexibility - Why it Matters

Prices for fuels used to generate electricity are unregulated in the U.S. and can be subject to dramatic fluctuation. G&T co-ops need the flexibility to raise rates in order to cover sharply higher prices for fuels, in addition to rising operating costs, and costs associated with existing mandated environmental requirements and those inevitably coming related for carbon emissions along with any capital investment associated with construction of new plants, among other factors.

Board Involvement/Rate Adjustment Mechanisms: The extent to which a G&T co-op can ensure timely and full recovery of its costs and investments will have an integral effect on its overall financial performance and thus its creditworthiness. Each G&T co-op's board of directors has a fiduciary responsibility to approve, or, where rate regulation applies, to seek regulatory approval of rates that ensure compliance with the financial covenants associated with debt indentures. To the extent that unexpected events arise, causing concerns about the ability to comply with covenants, the board should be expected to move quickly to adjust rates upward when needed. Also, variable cost adjustment mechanisms provide for more automatic changes in rates when costs change and increase the speed with which rates can be increased when costs increase. The extent to which variable cost adjustment mechanisms are available is especially important where regulatory jurisdiction applies to a G&T co-op. The existence of variable cost adjustment mechanisms is a credit strength, especially when rate adjustments can be implemented at frequent intervals. Such mechanisms mitigate liquidity pressures that might otherwise arise when the cost of fuels exceeds rates in effect at that time.

Degree of Reliance on Purchased Power: Most of the power supply needs of G&T co-op members are met from generating plants owned by the G&T co-ops. Some G&Ts rely on market purchases of power to meet a portion of the member needs because their owned resources are insufficient, uneconomic, or periodically unavailable.

Assessing the degree of reliance on purchased power to meet members' demand and the rationale behind that strategy is important because G&Ts who purchase large amounts of power from the market to meet member demands have less control over this obligation, particularly if forced to purchase power at inopportune times, which may increase price volatility for one of their largest costs. Relying on such a strategy also heightens the importance of liquidity, risk management policies and procedures, and counterparty credit assessment.

New Build Exposure Relative to Existing Asset Base: This factor is important because G&T co-ops largely finance capital investment with debt and rely upon rate increases to service the debt. When construction is delayed or runs above budget, the rate increases needed to cover the increased costs could lead to member resistance or, in the cases where regulation applies, cost recovery delays or disallowances.

Potential for Rate Shock Exposure: In many respects, the potential for rate shock exposure is linked to rate competitiveness, so we consider rate competitiveness as part of this sub-factor. Assessing the potential for rate shock exposure is important because a large rate increase can lead to member resistance even when the new higher level of rates is still competitive with other providers of power in the region. If the G&T co-op's rates are noticeably higher than other providers in its geographic area, regulatory relationships for those G&T co-ops subject to regulation could become strained and/or member unrest more broadly could lead to contract challenges or possible withdrawal from the co-op.

Rate Flexibility - How We Assess It for the Scorecard

Board Involvement/Rate Adjustment Mechanisms: The timing and extent to which a G&T co-op can increase rates is impacted by the activity of its board of directors and a number of rate adjustment mechanisms.

First, we assess how active a board has been from a historical perspective with respect to approving or seeking regulatory approval of rate increases and consider the extent to which past behavior might change. To the extent that unexpected events arise, causing concerns about the ability to comply with covenants, we believe the board should be expected to move quickly to adjust rates upward when needed. Those G&T co-ops whose boards of directors are exceptionally proactive in adjusting rates as necessary and who benefit from legislative statute that would preclude regulatory intervention in the future rate setting process would most likely receive the highest indicated outcomes. In contrast, G&T co-ops with less active or even inactive boards of directors and who otherwise face uncertainty surrounding the extent and timing of cost recovery would receive much lower indicated outcomes for this sub-factor.

With respect to situations where variable cost adjustment mechanisms apply, rates that can automatically adjust to fuel and/or purchased power cost increases without requiring action by the Board or regulators are viewed more favorably and generally result in a higher indicated outcome for this sub-factor. In instances where recovery of variable cost increases is deferred, we consider the time period over which recovery occurs, with shorter recovery periods being better from a liquidity and credit quality standpoint.

Degree of Reliance on Purchased Power: To measure the degree to which a G&T relies on purchased power in conducting its business, we divide the amount of megawatt hours it purchases during the most recent fiscal year by the total megawatt hours of energy it sells. This data can typically be found in the G&T co-op's latest annual report and/or other published data sources. In those instances where a G&T co-op relies on purchased power to meet less than 40% of its energy requirements during a given fiscal year, the indicated outcome for this sub-factor would typically be at least Baa and improve gradually as the percentage declines according to the Factor 2 table descriptions. Conversely, where the dependence on purchased power exceeds the 40% level, then the indicated outcome would typically be Ba or lower according to the Factor 2 table descriptions. In addition to the specific percentage calculation, we also take into account the extent to which purchases are made based solely on economic dispatch decisions (i.e. opportunistically purchasing cheaper power on the market instead of running owned generation plants). Such power purchases are usually made to maximize cost competitiveness in the G&T co-op's supply portfolio. We view purchases made on an economic dispatch basis to be less of a credit risk as compared to situations where the G&T co-op is relying extensively on more expensive spot market power purchases due to an unplanned outage at one of its owned generation plants or above market firm purchase power contracts required to meet customer demands for power.

New Build Exposure Relative to Existing Asset Base: To measure this sub-factor, we divide the estimated future capital expenditures for a particular G&T co-op over the next five years by the net property, plant, and equipment report for the latest fiscal year end. The lower the resulting percentage from this calculation is, the better the indicated outcome for the sub-factor will likely be, as the G&T will likely face less need to issue debt and increase rates to cover the higher financing costs.

Potential for Rate Shock Exposure: To measure the potential for rate shock exposure, we continue to look at the extent to which a G&T relies on purchased power to meet its energy demand during the latest fiscal year and its new build exposure. A lower percentage in both instances is generally viewed more favorably under the methodology. Our measurement criteria for this sub-factor also considers the G&T co-op's reliance on coal and other carbon emitting generating resources. Those G&T co-ops with a high reliance on such resources will typically be scored lower on this sub-factor due to their vulnerability to environmental regulations and accompanying carbon costs.

Cost competitive G&T co-ops have greater flexibility to raise rates to offset cost increases or to build additional equity and would therefore be more likely to receive a higher indicated outcome for this sub-factor than those G&T co-ops who are competitively challenged. Favorable characteristics include low or improving cost structure, lower wholesale prices versus peers, and low distribution member rates versus competitors in the region. We also assess a G&T co-op's prospects to realize future rate increases in order to offset increasing costs, as compared with others in the region, although consistent rate data is often not publicly available. Nonetheless, we seek whatever public information is available, as well as confidential information on a company by company basis.

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EXHIBIT 5

Factor 2 - Rate Flexibility (20%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Assess Board Involvement in Setting Rates / Variable Cost Adjustment Mechanisms	Exceptionally proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory/ political intervention in the rate setting process; Legislative statute to preclude regulatory intervention in the future rate setting process	Proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory/ political intervention in the rate setting process; No legislative statute to preclude regulatory intervention in the future rate setting process	Active board in support of timely rate filings; possibility for regulatory/political intervention in the rate setting process in certain instances; frequent fuel cost adjustment capability in place under regulatory practice; timely recovery of any deferrals	Reasonably active board in support of timely rate filings; annual fuel cost adjustment capability in place under regulatory practice; reasonably timely recovery of any deferrals	Inactive board; limited, if any ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	Inactive board; no ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	5%
Purchased Power/Total MWh Sales (%)	x < 5%	5% ≤ x < 20%	20% ≤ x < 30%	30% ≤ x < 40%	40% ≤ x < 60%	x ≥ 60%	5%
New Build Exposure (Prospective 5-yr New Build Capex as % Net PP&E)	x < 5%	5% ≤ x < 25%	25% ≤ x < 50%	50% ≤ x < 75%	75% ≤ x ≤ 120%	x > 120%	5%
Potential for Rate Shock Exposure	Better rates than all others in the region on a consistent basis; Extremely low (e.g. Less than 5% reliance on purchased power and less than 5% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 0-20% of generation from carbon fuels	Much better rates than most in the region on a consistent basis; Very low (e.g. less than 20% reliance on purchased power and less than 25% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 20-40% of generation from carbon fuels	Better rates than most in the region on a consistent basis; Low (e.g. less than 30% reliance on purchased power and/or less than 50% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 40-55% of generation from carbon fuels	Better rates than some and worse rates than some in the region on a consistent basis; Moderate (e.g. less than 40% reliance on purchased power and/or less than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 55-70% of generation from carbon fuels	Worse rates than most in the region on a consistent basis; High (e.g. greater than 40% reliance on purchased power or greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 70-85% of generation from carbon fuels	Worse rates than all in the region on a consistent basis; Very high (e.g. greater than 40% reliance on purchased power and greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 85-100% of generation from carbon fuels	5%

Source: Moody's Investors Service

Factor 3: Member/Owner Profile

Member/Owner Profile - Why it Matters

Assessing the member/owner profile of a G&T co-op is important because the members who own the G&T co-op are also its primary source of cash flow. Similar to the way we would assess the counterparty credit risk for an IOU that sells sizable amounts of power to another entity, or buys significant amounts of power from a wholesale power producer, we focus on the overall creditworthiness of the members. Although not specifically weighted, we seek information about the members' expected consolidated demand growth and their consolidated assets when evaluating the overall member profile. The following two sub-factors, which are weighted at 5% each, provide good insight into the members' creditworthiness and ability to meet obligations to the G&T co-op under the long-term wholesale power contract.

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Residential Sales as a Percentage of Total Sales: The diversity of the members' retail customer mix is important in our analysis of G&T co-ops because substantial reliance upon any single customer or a small number of customers (such as large industrial customers) tends to be associated with greater variability of revenue. Members who own the G&T co-ops tend to serve large residential customer bases, with a majority of energy being sold to such customers, although some sales may be to more volatile industrial and commercial customers. A higher percentage of sales to residential customers is favorable because such sales are generally more stable and predictable.

Members Consolidated Equity to Capitalization: The financial condition of the member/owners, as measured in part by the members' consolidated equity to capitalization, is important because it affects their ability to perform under the wholesale power contracts that members have with their G&T co-op. For the most part, distribution co-ops carry less business and financial risk than G&T co-ops. The difference in the financial strength is largely attributable to the fact that the RUS has historically set tighter financial covenants for the distribution co-ops than for the G&T co-ops. In addition, the distribution co-ops are far less capital-intensive than G&T co-ops who own generation assets. Distribution co-ops typically maintain higher levels of equity to total capitalization and stronger interest coverage ratios than G&T co-ops.

Member/Owner Profile - How We Assess It for the Scorecard

Residential Sales as a Percentage of Total Sales: To measure this sub-factor, we first generally aggregate the individual residential energy sales and total energy sales for each member/owner of a particular G&T co-op in the latest fiscal year. This information is generally available through requests made to the G&T co-op because their members provide this data to them. The aggregate residential energy sales level is then divided by the aggregate total energy sales level to derive the aggregate percentage for the year. Under the Methodology, a higher percentage of more stable and predictable residential sales is viewed more favorably than a concentration of sales to large commercial and/or industrial customers.

Members Consolidated Equity to Capitalization: This sub-factor is measured by simply aggregating each member's total equity and debt as reported for the latest fiscal year end. The aggregate totals are then used to divide total members' equity by the sum of total members' debt plus equity. Members generally file financial statements with the RUS or otherwise make such statements available to the G&T that they have an ownership interest in. The large majority of the G&T co-ops that are covered by the methodology fall into the Baa category with consolidated member equity to capitalization in the range of 25% to 50%.

EXHIBIT 6

Factor 3 - Member / Owner Profile (10%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Residential Sales/ Total Sales (%)	x ≥ 80%	75% ≤ x < 80%	50% ≤ x < 75%	40% ≤ x < 50%	20% ≤ x < 40%	x < 20%	5%
Members' Consolidated Equity/Capitalization (%)	x ≥ 65%	55% ≤ x < 65%	50% ≤ x < 55%	25% ≤ x < 50%	20% ≤ x < 25%	x < 20%	5%

Source: Moody's Investors Service

Factor 4: G&T Financial Metrics

G&T Financial Metrics - Why it Matters

Financial strength is an important indicator of a G&T co-op's ability to meet its obligations, including debt service. We consider historical coverage ratios and also place a significant emphasis on the expected trend for coverage metrics when assessing the credit risk of G&T co-ops. Although we continue to note that some G&T co-ops have large investment portfolios that considerably augment the bottom line, we consider

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it important that the G&T co-op be profitable on an operating basis. G&T co-ops that rely extensively on profits from investment portfolios and diversified operations to compensate for negative G&T operating margins are viewed negatively.

Scores under Factor 4 may be higher or lower than what might be produced based on historical results, depending on our view of expected future financial performance.

Times Interest Earned Ratio (TIER) and Debt Service Coverage Ratio (DSC): These two ratios are important because they have governed RUS loan documentation for many years. In addition to TIER and DSC, we also look at margins for interest (MFI) as defined in certain indentures.

Funds from Operations Coverage of Interest (FFO/Interest) and FFO/Debt: The FFO/Interest and FFO/Debt metrics are important because they provide insight regarding the amount and quality of a G&T co-op's cash flow and its ability to service its debt.

Equity/Total Adjusted Capitalization: We evaluate the G&T co-op's equity as a percentage of total adjusted capitalization to see how much flexibility there is in the balance sheet to absorb unexpected events. When measuring the level of equity cushion, G&T co-ops and the RUS have tended to rely on equity expressed as a percentage of total assets. However, we and many investors prefer to measure equity as a percentage of total capitalization, because it facilitates comparison with IOU capital structures.

G&T Financial Metrics - How We Assess It for the Scorecard

The ratios used as a basis for this methodology are three-year averages of calculations using the latest three fiscal year-end statements, including our standard adjustments. Three-year averages are used in part to smooth out some of the year to year volatility in financial performance and financial statement ratios. The ranges for each of the five metrics that would correspond to a particular indicated outcome category appear in the table at the bottom of this section. The individual metric definitions are as follows:

TIER:

(Net margins, as represented by net profit after tax before unusual items + Interest + Income Tax) / Interest

DSCR:

(Net margins, as represented by net profit after tax before unusual items + Interest + Depreciation & Amortization) / (Interest + Principal Payment)

FFO / Interest:

(Funds from operations + Interest expense)/ Interest expense

FFO / Debt:

Funds from operations / (Short-Term Debt + Long-Term Debt, gross)

Equity / Total Capitalization:

(Deferred Taxes + Minority or Non-controlling Interest + Book Equity) / (Short-Term Debt + Long-Term Debt, gross + Deferred Taxes + Minority or Non-controlling Interest + Book Equity)

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EXHIBIT 7

Factor 4 - 3-Year Average G&T Financial Metrics (40%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
TIER	x ≥ 1.6x	1.4x ≤ x < 1.6x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
DSC	x ≥ 1.9x	1.4x ≤ x < 1.9x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
FFO/Debt	x ≥ 15%	10% ≤ x < 15%	6% ≤ x < 10%	3% ≤ x < 6%	2% ≤ x < 3%	x < 2%	10%
FFO/Interest	x ≥ 3.25x	2.5x ≤ x < 3.25x	2.0x ≤ x < 2.5x	1.5x ≤ x < 2.0x	1.2x ≤ x < 1.5x	x < 1.2x	10%
Equity/Total Capitalization	x ≥ 50%	35% ≤ x < 50%	20% ≤ x < 35%	5% ≤ x < 20%	3% ≤ x < 5%	x < 3%	10%

Source: Moody's Investors Service

Factor 5: G&T Size

G&T Size - Why it Matters

Size, together with Factor 3, Member/Owner Profile, has the lowest weighting of the five factors because it tends to be less important for entities, such as G&T co-ops, that are subject to limited competition. That said, we still find that size, as measured by the following two sub-factors, which are weighted at 5% each, does matter.

Megawatt hour sales: This sub-factor is important because it is an indicator of economies of scale (i.e., a G&T co-op is better off if it can spread its fixed costs over a larger number of megawatt hours of electricity, thereby increasing its price competitiveness).

Net Property, Plant, and Equipment: This sub-factor is important because G&T co-ops can benefit from having a larger pool of assets and a more diverse source of fuels to run the generation assets it owns. A G&T co-op that has its assets concentrated in one generating plant could be subject to extreme cost pressures to the extent that it has to buy power on the open market due to an extended outage at its sole generating plant. Similarly, overdependence on one particular fuel source could materially raise costs during a period of prolonged price increases for that commodity.

G&T Size - How We Assess It for the Scorecard

We identify the amount of megawatt hour sales and net property, plant, and equipment data primarily from the G&T co-op's latest annual report. See the Factor 5 table below for the ranges that would apply for a particular indicated outcome for the two sub-factors in Factor 5.

EXHIBIT 8

Factor 5 - G&T Size (10%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Megawatt hour sales (Millions of MWhs)	x ≥ 50	20 ≤ x < 50	11 ≤ x < 20	5 ≤ x < 11	3 ≤ x < 5	x < 3	5%
Net PP&E ($ in Billions)	x ≥ $5 billion	2 ≤ x < 5	1 ≤ x < 2	0.4 ≤ x < 1	0.3 ≤ x < 0.4	x < $0.3 billion	5%

Source: Moody's Investors Service

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

The rating methodology scorecard represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that would enable the scorecard to map more closely to actual ratings. Accordingly, the five factors in the scorecard do not constitute an exhaustive treatment of all the considerations that are important for ratings of entities in the U.S. electric generation & transmission cooperative sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used for mapping in the scorecard is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we cannot publish or otherwise disclose. In other cases, we estimate future results based upon past performance, industry trends 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, sector trends, new technology, regulatory and legal actions, as well as management's appetite for additional debt to finance capital expenditures, or unexpected external transfers to affiliated governments or enterprises.

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 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 G&T co-ops, such as the quality and experience of management, assessments of governance and the quality of financial reporting and information disclosure. The assessment of these factors can be highly subjective and vary over time. Therefore, ranking these factors by rating category in a scorecard would 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, and possible government interference in some state, provincial or local governments. Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies, and macroeconomic trends also affect ratings. While these are important considerations, it is not possible to precisely express these in the rating methodology scorecard without making the scorecard excessively complex and significantly less transparent. Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the scorecard.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the scorecard. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk but two identical G&T co-ops 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 will enable a good approximation of our view on the credit quality of entities in the U.S. electric generation & transmission cooperative sector. Ratings consider additional factors, including our assessment of future operating performance that may deviate from historical performance, the quality of management, governance, financial controls, liquidity management, seasonality and event risk. The analysis of these factors remains an integral part of our rating process.

Management Quality

The quality of management is an important factor supporting the credit strength of a G&T co-op. We normally meet with senior executives to assess management's business strategies, policies, and philosophies, and evaluate management performance relative to performance of peers and our projections.

An established managerial record provides us with insight into management's likely future performance in stressed situations. This can be an indicator of management's tendency to stray significantly from what may be an effective current business philosophy, or conversely, to adopt changes where they are warranted by new sets of circumstances.

Governance

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

Financial Controls

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

Weaknesses in the overall financial reporting processes, financial report restatements or delays in producing audited financial statements can be indications of a potential breakdown in internal controls.

Liquidity Management

Liquidity is a meaningful credit consideration for all companies but is especially critical in lower rated companies as these issuers have less operating and financial flexibility. We form an opinion on a company's likely near-term liquidity requirements from the perspective of both the sources and uses of cash. This may include monitoring bank covenants and compliance cushions to assess whether a company is likely to require covenants relief in the event of even a modest industry downturn or of an issuer-specific decline of performance.

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 a drastic and unfavorable change in the ownership base, a recapitalization, or an unexpected change in rates or terms of a material contract, weather events, pandemics, litigation, and changes in governing regulation, legislation or law.

Appendix: US Electric G&T Cooperative Methodology Factor Scorecard

Factor 1: Long-Term Wholesale Power Supply Contracts and Regulatory Status

Weighting: 20%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Percentage of Member Load Served under Wholesale Power Contracts and Regulatory Status	100% and G&T and its Distribution Member/Owner Cooperatives are Not Rate Regulated by State Commission; Legislative statute to preclude regulatory intervention in the future rate setting process; Very Good Contractual Relationships	100% and G&T is Not Rate Regulated by State Commission; No legislative statute to preclude regulatory intervention in the future G&T rate setting process; Some Distribution Member/Owner Cooperatives May Be Subject to Rate Regulation by State Commission; Very Supportive Commission Practices; Very Good Regulatory/ Contractual Relationships	> 80% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated by State Commission; Very Supportive Commission Practices; Very Good Regulatory/ Contractual Relationships	> 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Moderately Supportive Commission Practices; Reasonably Good Regulatory/ Contractual Relationships	< 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Unsupportive Commission Practices; Generally Difficult Regulatory/ Contractual Relationships	< 60% and/or G&T is Rate Regulated by State Commission; Most Distribution Member/Owner Cooperatives are Rate Regulated By State Commission; Very Unsupportive Commission Practices; Often Contentious Regulatory/ Contractual Relationships	20%

Factor 2: Rate Flexibility

Weighting: 20%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Assess Board Involvement in Setting Rates / Variable Cost Adjustment Mechanisms	Exceptionally proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory/political intervention in the rate setting process; Legislative statute to preclude regulatory intervention in the future rate setting process	Proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory/political intervention in the rate setting process; No legislative statute to preclude regulatory intervention in the future rate setting process	Active board in support of timely rate filings; possibility for regulatory/political intervention in the rate setting process in certain instances; frequent fuel cost adjustment capability in place under regulatory practice; timely recovery of any deferrals	Reasonably active board in support of timely rate filings; annual fuel cost adjustment capability in place under regulatory practice; reasonably timely recovery of any deferrals	Inactive board; limited, if any ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	Inactive board; no ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	5%
Purchased Power/Total MWh Sales (%)	x < 5%	5% ≤ x < 20%	20% ≤ x < 30%	30% ≤ x < 40%	40% ≤ x < 60%	x ≥ 60%	5%
New Build Exposure (Prospective 5-yr New Build Capex as % Net PP&E)	x < 5%	5% ≤ x < 25%	25% ≤ x < 50%	50% ≤ x < 75%	75% ≤ x ≤ 120%	x > 120%	5%
Potential for Rate Shock Exposure	Better rates than all others in the region on a consistent basis; Extremely low (e.g. Less than 5% reliance on purchased power and less than 5% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 0-20% of generation from carbon fuels	Much better rates than most in the region on a consistent basis; Very low (e.g. less than 20% reliance on purchased power and less than 25% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 20-40% of generation from carbon fuels	Better rates than most in the region on a consistent basis; Low (e.g. less than 30% reliance on purchased power and/or less than 50% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 40-55% of generation from carbon fuels	Better rates than some and worse rates than some in the region on a consistent basis; Moderate (e.g. less than 40% reliance on purchased power and/or less than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 55-70% of generation from carbon fuels	Worse rates than most in the region on a consistent basis; High (e.g. greater than 40% reliance on purchased power or greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 70-85% of generation from carbon fuels	Worse rates than all in the region on a consistent basis; Very high (e.g. greater than 40% reliance on purchased power and greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 85-100% of generation from carbon fuels	5%

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Factor 3: Member / Owner Profile

Weighting: 10%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Residential Sales/Total Sales (%)	x ≥ 80%	75% ≤ x < 80%	50% ≤ x < 75%	40% ≤ x < 50%	20% ≤ x < 40%	x < 20%	5%
Members' Consolidated Equity/Capitalization (%)	x ≥ 65%	55% ≤ x < 65%	50% ≤ x < 55%	25% ≤ x < 50%	20% ≤ x < 25%	x < 20%	5%

Factor 4: 3-Year Average G&T Financial Metrics

Weighting: 40%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
TIER	x ≥ 1.6x	1.4x ≤ x < 1.6x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
DSC	x ≥ 1.9x	1.4x ≤ x < 1.9x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
FFO/Debt	x ≥ 15%	10% ≤ x < 15%	6% ≤ x < 10%	3% ≤ x < 6%	2% ≤ x < 3%	x < 2%	10%
FFO/Interest	x ≥ 3.25x	2.5x ≤ x < 3.25x	2.0x ≤ x < 2.5x	1.5x ≤ x < 2.0x	1.2x ≤ x < 1.5x	x < 1.2x	10%
Equity/Total Capitalization	x ≥ 50%	35% ≤ x < 50%	20% ≤ x < 35%	5% ≤ x < 20%	3% ≤ x < 5%	x < 3%	10%

Factor 5: G&T Size

Weighting: 10%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Megawatt hour sales (Millions of MWhs)	x ≥ 50	20 ≤ x < 50	11 ≤ x < 20	5 ≤ x < 11	3 ≤ x < 5	x < 3	5%
Net PP&E ($ in Billions)	x ≥ $5 billion	2 ≤ x < 5	1 ≤ x < 2	0.4 ≤ x < 1	0.3 ≤ x < 0.4	x < $0.3 billion	5%

Source: Moody's Investors Service

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Moody's Related Publications

Credit ratings are primarily determined through the application of 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. A list 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.

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