

THIS FILING IS

Item 1: An Initial (Original) Submission OR Resubmission No.



**FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of
Major Electric Utilities, Licensees
and Others and Supplemental
Form 3-Q: Quarterly Financial Report**

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)

Union Electric Company

Year/Period of Report
End of: 2024/ Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

- one million megawatt hours of total annual sales,
- 100 megawatt hours of annual sales for resale,
- 500 megawatt hours of annual power exchanges delivered, or
- 500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at <https://eCollection.ferc.gov>, and according to the specifications in the Form 1 and 3-Q taxonomies.

The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

<u>Schedules</u>	<u>Pages</u>
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert

the List of Schedules, pages 2 and 3.

Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at <https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online>.

Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from <https://www.ferc.gov/general-information-0/electric-industry-forms>.

When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

'Person' means an individual or a corporation;

'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power;

"project" means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

"To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on

FERC FORM NO. 1 (ED. 03-07)

GENERAL PENALTIES

The Commission may assess up to \$1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

**FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER**

IDENTIFICATION

01 Exact Legal Name of Respondent Union Electric Company	02 Year/ Period of Report End of: 2024/ Q4
03 Previous Name and Date of Change (If name changed during year) /	
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 1901 Chouteau Avenue, St. Louis, MO 63103	
05 Name of Contact Person Mitchell Lansford	06 Title of Contact Person Senior Director, Financial Reporting and Regulatory Accounting
07 Address of Contact Person (Street, City, State, Zip Code) 1901 Chouteau Avenue, St. Louis, MO 63103	
08 Telephone of Contact Person, Including Area Code (314) 861-5413	09 This Report is An Original / A Resubmission (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission
10 Date of Report (Mo, Da, Yr) 04/08/2025	
Annual Corporate Officer Certification	
The undersigned officer certifies that: I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.	
01 Name Laura M. Moore	03 Signature Laura M. Moore
02 Title Controller, Union Electric Company	04 Date Signed (Mo, Da, Yr) 04/08/2025
Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.	

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106	
7	Important Changes During the Year	108	
8	Comparative Balance Sheet	110	
9	Statement of Income for the Year	114	
10	Statement of Retained Earnings for the Year	118	
12	Statement of Cash Flows	120	
12	Notes to Financial Statements	122	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	None
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	
22	Materials and Supplies	227	
23	Allowances	228	
24	Extraordinary Property Losses	230a	None
25	Unrecovered Plant and Regulatory Study Costs	230b	

26	Transmission Service and Generation Interconnection Study Costs	231	None
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	None
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	Not applicable
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	
47	Purchased Power	326	
48	Transmission of Electricity for Others	328	
49	Transmission of Electricity by ISO/RTOs	331	Not applicable
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant (Account 403, 404, 405)	336	
53	Regulatory Commission Expenses	350	
54	Research, Development and Demonstration Activities	352	
55	Distribution of Salaries and Wages	354	
56	Common Utility Plant and Expenses	356	None
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	

60	Monthly ISO/RTO Transmission System Peak Load	400a	Not applicable
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	
64	Hydroelectric Generating Plant Statistics	406	
65	Pumped Storage Generating Plant Statistics	408	
66	Generating Plant Statistics Pages	410	
66.1	Energy Storage Operations (Large Plants)	414	
66.2	Energy Storage Operations (Small Plants)	419	
67	Transmission Line Statistics Pages	422	
68	Transmission Lines Added During Year	424	None
69	Substations	426	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: <input checked="" type="checkbox"/> Two copies will be submitted <input type="checkbox"/> No annual report to stockholders is prepared		

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
GENERAL INFORMATION			
<p>1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.</p> <p>Michael Moehn, Senior Executive Vice President and Chief Financial Officer 1901 Chouteau Avenue, St. Louis, MO 63103</p>			
<p>2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.</p> <p>State of Incorporation: MO Date of Incorporation: 1922-11-21 Incorporated Under Special Law:</p>			
<p>3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.</p> <p>(a) Name of Receiver or Trustee Holding Property of the Respondent: N/A (b) Date Receiver took Possession of Respondent Property: (c) Authority by which the Receivership or Trusteeship was created: N/A (d) Date when possession by receiver or trustee ceased:</p>			
<p>4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.</p> <p>Electric and gas utility services in Missouri</p>			
<p>5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?</p> <p>(1) <input type="checkbox"/> Yes (2) <input checked="" type="checkbox"/> No</p>			

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: StateOfIncorporation
Incorporated in Missouri as Missouri Electric Light and Power Co. on 11/21/1922. Legal name changed to Union Electric Light and Power Company on 12/15/1922, to Union Electric Co. of Missouri on 5/29/1937, and to present name on 4/23/1956.

FERC FORM No. 1 (ED. 12-87)

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
CONTROL OVER RESPONDENT			
1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.			
Ameren Corporation, a public utility holding company under PUCHA 2005, owns all of the outstanding common stock of the Respondent.			

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	STARS Alliance LLC	Formed to increase efficiency and reduce costs related to the operation of the members' nuclear generation facilities.	25	(a) (1)
2	Ameren Missouri Renewables Holdco LLC	Renewable generation development	100	(b) (2)
3	BREC Holding Company LLC	Renewable generation development	100	(2)
4	HFREC Holding Company, LLC	Renewable generation development	100	(2)
5	Ameren Missouri Securitization Funding I, LLC	For the purpose of issuing securitized utility tariff bonds	100	

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FOOTNOTE DATA

(a) Concept: FootnoteReferences
(1) Joint membership with Arizona Public Service, Pacific Gas and Electric Company and Wolf Creek Nuclear Operating Company.
(b) Concept: FootnoteReferences
(2) This footnote applies to lines 2, 3, and 4, column (d). This company has been dissolved as of December 31, 2024.

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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OFFICERS

- Report below the name, title and salary for each executive officer whose salary is \$50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
- If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	Chairman and President	Mark C. Birk	650,000	2024-01-01	2024-12-31
2	^(a) Senior Executive Vice President and Chief Financial Officer	Michael L. Moehn	860,000	2024-01-01	2024-12-31
3	Senior Vice President and Chief Nuclear Officer	Fadi M. Diya	610,000	2024-01-01	2024-12-31
4	^(b) Executive Vice President, General Counsel and Secretary	Chonda J. Nwamu	658,000	2024-01-01	2024-12-31
5	^(c) Senior Vice President, Finance and Chief Accounting Officer	Theresa A. Shaw	415,000	2024-01-01	2024-12-31
6	Vice President	John G. Beck	315,000	2024-01-01	2024-12-31
7	Senior Vice President and Chief Renewable Development Officer	Ajay K. Arora	372,800	2024-01-01	2024-12-31
8	^(d) Vice President	Carol L. Wuerffel	300,700	2024-01-01	2024-12-31
9	Vice President	Kevin A. DeGraw	338,800	2024-01-01	2024-12-31
10	^(e) Vice President and Chief Procurement Officer	Pardeep S. Gill	252,891	2024-01-01	2024-10-18
11	Vice President	Tara K. Oglesby	299,700	2024-01-01	2024-12-31
12	^(f) Vice President and Treasurer	Darryl T. Sagel	380,000	2024-01-01	2024-12-31
13	Vice President	Warren T. Wood	320,600	2024-01-01	2024-12-31
14	Site Vice President	Kent C. Scott	390,000	2024-01-01	2024-12-31
15	^(g) Vice President and Deputy General Counsel	Stephen C. Lee	333,400	2024-01-01	2024-12-31
16	Vice President	Timothy E. Lafser	322,500	2024-01-01	2024-12-31
17	Vice President	Ryan M. Arnold	270,000	2024-01-01	2024-12-31

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FOOTNOTE DATA

(a) Concept: OfficerTitle Officer's salary is paid by Ameren Services Company, with costs shared among Ameren Corporation subsidiaries.
(b) Concept: OfficerTitle Officer's salary is paid by Ameren Services Company, with costs shared among Ameren Corporation subsidiaries.
(c) Concept: OfficerTitle Officer's salary is paid by Ameren Services Company, with costs shared among Ameren Corporation subsidiaries.
(d) Concept: OfficerTitle Officer's salary is paid by Ameren Services Company, with costs shared among Ameren Corporation subsidiaries.
(e) Concept: OfficerTitle Officer's salary is paid by Ameren Services Company, with costs shared among Ameren Corporation subsidiaries.
(f) Concept: OfficerTitle Officer's salary is paid by Ameren Services Company, with costs shared among Ameren Corporation subsidiaries.
(g) Concept: OfficerTitle Officer's salary is paid by Ameren Services Company, with costs shared among Ameren Corporation subsidiaries.

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Mark C. Birk, Chairman & President	1901 Chouteau Avenue, St. Louis, MO 63103	false	false
2	Fadi M. Diya, Senior Vice President & Chief Nuclear Officer	Junction Highway CC and Highway O, Fulton, MO 65251	false	false
3	Michael L. Moehn, Senior Executive Vice President & Chief Financial Officer	1901 Chouteau Avenue, St. Louis, MO 63103	false	false
4	Chonda J. Nwamu, Executive Vice President, General Counsel & Secretary	1901 Chouteau Avenue, St. Louis, MO 63103	false	false

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	Attachment O	
2	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Original Volume No. 1	ER98-1438-000
3	Midcontinent Independent System Operator, Inc. FERC Electric Tariff First Revised Volume No. 1	ER98-1438-007
4	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Second Revised Volume No. 1	ER04-458-004
5	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Second Revised Volume No. 1	ER04-895-000
6	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Second Revised Volume No. 1	ER05-122-000
7	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Third Revised Volume No. 1	ER05-1085-001; ER04-458-008
8	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Third Revised Volume No. 1	ER04-691-014; EL04-104-013; EL04-104-032
9	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Third Revised Volume No. 1	ER04-691-034; EL04-104-013; EL04-104-032
10	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Third Revised Volume No. 1	ER06-159-000
11	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Third Revised Volume No. 1	ER07-113-000
12	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Third Revised Volume No. 1	ER07-113-002
13	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1	OA08-4-001
14	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1	ER09-15-001
15	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Third Revised Volume No. 1	ER09-91-000
16	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1	ER09-91-000; ER09-573-000
17	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1	ER09-1657-000
18	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1	ER09-1779-000
19	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1	ER10-1492-000

20	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER10-1997-000
21	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER10-1997-001
22	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER11-2700-000
23	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER11-2700-004
24	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER11-3251-000
25	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER11-3704-000
26	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER12-297-000
27	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER12-310-000
28	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER12-578-000
29	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER12-1667-000
30	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER13-307-000
31	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER13-674-000
32	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1	ER13-674-002
33	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-1547-000
34	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-1827-000
35	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-2379-000
36	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-102-000
37	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-421-000 and -001
38	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-260-000
39	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER14-649-000
40	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-2379-003
41	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-142-000
42	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-277-000
43	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-358-000
44	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER13-2379-004

45	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1067-000
46	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1210-000
47	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1413-000
48	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1490-000
49	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1067-001
50	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-2447-000
51	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-314-000
52	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-1210-001
53	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER15-2364-000
54	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-18-000
55	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-1322-000
56	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER16-1333-000
57	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-893-000
58	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-2323-000
59	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-2323-001
60	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-94-00
61	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-1982-000
62	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-788-000
63	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER18-1159-000
64	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-249-000
65	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-652-000
66	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-2050-000
67	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER19-2050-002
68	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER20-1167-000
69	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER20-1080-000

70	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-200-000
71	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-262-000
72	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-1510-000
73	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-1516-000
74	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-2133-000
75	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER17-215-001
76	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER21-2050-000
77	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER22-1113-000
78	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER22-1363-000
79	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER22-1602-000
80	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER20-1298-000, -001, -002, -003, -004 and -005
81	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER22-2768-000
82	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER23-2298-000
83	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff	ER23-2707-000
84	Attachment GG	
85	Midcontinent Independent System Operator, Inc FERC Electric Tariff Third Revised Volume No. 1 - GG	ER06-18-000
86	Midcontinent Independent System Operator, Inc FERC Electric Tariff Third Revised Volume No. 1 - GG	ER06-18-008
87	Midcontinent Independent System Operator, Inc FERC Electric Tariff Fourth Revised Volume No. 1 - GG	ER09-15-000
88	Midcontinent Independent System Operator, Inc FERC Electric Tariff Third Revised Volume No. 1 - GG	ER09-91-000
89	Midcontinent Independent System Operator, Inc FERC Electric Tariff Fourth Revised Volume No. 1 - GG	ER09-506-000
90	Midcontinent Independent System Operator, Inc FERC Electric Tariff Fourth Revised Volume No. 1 - GG	ER09-1431-000
91	Midcontinent Independent System Operator, Inc FERC Electric Tariff Fourth Revised Volume No. 1 - GG	ER09-1657-000
92	Midcontinent Independent System Operator, Inc FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER10-1997-000
93	Midcontinent Independent System Operator, Inc FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER10-1997-001
94	Midcontinent Independent System Operator, Inc FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER11-28-000
95	Midcontinent Independent System Operator, Inc FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER11-134-000

96	Midcontinent Independent System Operator, Inc FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER11-28-001
97	Midcontinent Independent System Operator, Inc FERC Electric Tariff Fifth Revised Volume No. 1 - GG	(a) ER11-2565-000*
98	Midcontinent Independent System Operator, Inc FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER11-3279-000
99	Midcontinent Independent System Operator, Inc FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER12-334-000
100	Midcontinent Independent System Operator, Inc FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER12-480-000
101	Midcontinent Independent System Operator, Inc FERC Electric Tariff Fifth Revised Volume No. 1 - GG	ER13-674-000
102	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - GG	ER14-261-000
103	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - GG	ER14-421-000
104	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - GG	ER11-3279-001
105	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - GG	ER16-1313-000
106	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - GG	ER16-1534-000
107	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - GG	ER18-867-000
108	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - GG	ER22-90-000
109	Attachment MM	
110	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fourth Revised Volume No. 1 - MM	ER10-1791
111	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER10-1997-000
112	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER10-1997-001
113	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER12-312-000
114	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER12-450-000
115	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER12-480-000
116	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER12-480-002
117	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER12-480-003
118	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER12-715-000
119	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER12-715-002
120	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER13-263-001
121	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER13-674-000

122	Midcontinent Independent System Operator, Inc. FERC Electric Tariff Fifth Revised Volume No. 1 - MM	ER13-1169-000
123	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER13-1169-001
124	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER13-2468-000
125	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER12-480-006
126	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER14-421-000
127	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER12-480-007
128	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER15-1689-000
129	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER15-2364-000
130	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER16-18-000
131	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER16-392-000
132	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER16-1534-000
133	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER16-2417-000
134	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER18-94-000
135	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER18-1159-000
136	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER18-1982-000
137	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER22-90-000
138	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER19-465-000
139	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER22-1579-000
140	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER23-1532-000
141	Midcontinent Independent System Operator, Inc. - FERC Electric Tariff - MM	ER23-2311-000

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: ProceedingDocketNumber

The filing in Docket No. ER11-2565-000 is a compliance filing that appears to be the same filing assigned Docket No. ER11-28-001. FERC issued an order accepting the filing ER11-28-001, but did not reference Docket No. ER11-2565-000. MISO withdrew the filing in Docket No. ER11-2565 on January 12, 2011.

FERC FORM No. 1 (NEW. 12-08)

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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If yes, provide a listing of such filings as contained on the Commission's eLibrary website.

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20150316-5251	03/16/2015	ER15-1299-000	Informational filing for 2013 Annual Update based on 2013 FERC Form 1.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
2	20150406-5147	04/06/2015	ER15-1299-000	Informational filing for 2013 Annual Update based on 2013 FERC Form 1.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
3	20160314-5240	03/14/2016	ER16-1170-000	Informational filing for 2014 Annual Update based on 2014 FERC Form 1.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
4	20170313-5381	03/13/2017	ER17-1197-000	Informational filing for 2015 Annual Update based on 2015 FERC Form 1.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
5	20180315-5170	03/15/2018	ER18-1121-000	Informational filing for 2016 Annual Update based on 2016 FERC Form 1.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
6	20190313-5132	03/13/2019	ER19-1274-000	Informational filing for 2017 Annual Update based on 2017 FERC Form 1.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
7	20200310-5195	03/10/2020	ER20-1236-000	Informational filing for 2018 Annual Update based on 2018 FERC Form 1.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
8	20210312-5174	03/12/2021	ER21-1354-000	Informational filing for 2019 Annual Update based on 2019 FERC Form 1.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
9	20220311-5299	03/11/2022	ER22-1282-000	Informational filing for 2020 Annual Update based on 2020 FERC Form 1.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
10	20230314-5069	03/14/2023	ER23-1341-000	Informational filing for 2021 Annual Update based on 2021 FERC Form 1.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
11	20240313-5146	03/13/2024	ER24-1475-000	Informational filing for 2022 Annual Update based on 2022 FERC Form 1.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
12	20250312-5107	03/12/2025	ER25-1568-000	Informational filing for 2023 Annual Update based on 2023 FERC Form 1.	Midcontinent Independent System Operator, Inc. FERC Electric Tariff
13	(a) See Footnote				

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: AccessionNumber

Per the Formula Rate Protocols in Dockets EL12-35 and ER13-2379 that were effective January 1, 2014, Union Electric Company shall submit to FERC an Informational Filing of its Annual Update by March 15 of each year.

FERC FORM NO. 1 (NEW. 12-08)

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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INFORMATION ON FORMULA RATES - Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
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Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1. None

2. On June 25, 2024, Ameren Missouri closed on the transaction to acquire Cass County Solar Project, LLC, a 150 MW solar generation facility. Ameren Missouri acquired the project from Savion, LLC. The project achieved commercial operation in December 2024. There were no FERC approvals needed for this transaction since it was acquired prior to it becoming commercially operational. The Missouri Public Service Commission approved a certificate of convenience and necessity authorizing Ameren Missouri to purchase the project in Docket No. EA-2023-0286.

On September 26, 2024, Ameren Missouri closed on the transaction to acquire Boomtown Solar Energy Solar LLC, a 150 MW solar generation facility. Ameren Missouri acquired the project from Invenergy LLC. The project achieved commercial operation in December 2024. The FERC approved a Section 203 filing authorizing the transaction in Docket No. EC23-85-000. The Missouri Public Service Commission approved a certificate of convenience and necessity authorizing Ameren Missouri to purchase the project in Docket No. EA-2022-0245.

On October 30, 2024, Ameren Missouri closed on the transaction to acquire Huck Finn Solar, LLC, a 200 MW solar generation facility. Ameren acquired the project from EDF Renewables Development, Inc. The project achieved commercial operation in December 2024. The FERC approved a Section 203 filing authorizing the transaction in Docket No. EC23-33-000. The Missouri Public Service Commission approved a certificate of convenience and necessity authorizing Ameren Missouri to purchase the project in Docket No. EA-2022-0244.

3. None

4. None

5. None

6. The respondent had a net decrease of \$475.5 million during the year ended December 31, 2024 over the prior year. The respondent had no short-term debt as of December 31, 2024. FERC authority granted in Docket No. ES25-13-000.

7. None

8. During the first quarter, 2,314 represented employees received a 3.5% general wage increase. The current estimated annual cost effect of this increase amounts to \$7,843,007. During the third quarter, 88 represented employees received a 3.1% general wage increase. The current estimated annual cost effect of this increase amounts to \$178,443.

9. See Note 2 – Rate and Regulatory Matters, Note 9 – Callaway Energy Center, and Note 14 – Commitments and Contingencies in the “Notes to Financial Statements.”

10. None

12. Not applicable

13. Effective March 22, 2024 Bhavani Amirthalingam relinquished her position as a Director of the Company.
Effective October 18, 2024, Pardeep S. Gill, who served as a Vice President and Chief Procurement Officer of the Company, resigned from the Company.

14. Not applicable

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200	26,556,014,440	24,853,183,987
3	Construction Work in Progress (107)	200	995,267,308	930,891,460
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		27,551,281,748	25,784,075,447
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	10,066,481,231	9,888,604,039
6	Net Utility Plant (Enter Total of line 4 less 5)		17,484,800,517	15,895,471,408
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	162,719,148	164,255,078
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		105,414,977	9,016,711
9	Nuclear Fuel Assemblies in Reactor (120.3)		246,382,167	246,216,079
10	Spent Nuclear Fuel (120.4)		2,025,505,777	2,022,587,714
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	2,200,255,554	2,119,888,805
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		339,766,515	322,186,777
14	Net Utility Plant (Enter Total of lines 6 and 13)		17,824,567,032	16,217,658,185
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		9,029,081	6,462,074
19	(Less) Accum. Prov. for Depr. and Amort. (122)		1,254,086	1,051,694
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	1,327,858	
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		146,832	114,910
25	Sinking Funds (125)			
26	Depreciation Fund (126)		1,342,170,136	1,149,677,255
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		218,357,100	161,940,721
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)		2,213,042	3,241,744

31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		1,571,989,963	1,320,385,010
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		47,704	112,764
36	Special Deposits (132-134)		142,450	142,450
37	Working Fund (135)		10,000	10,000
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		224,895,430	219,659,718
41	Other Accounts Receivable (143)		26,704,589	22,856,738
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		11,580,773	12,166,196
43	Notes Receivable from Associated Companies (145)		42,775,000	
44	Accounts Receivable from Assoc. Companies (146)		69,658,472	102,866,860
45	Fuel Stock (151)	227	112,665,704	108,761,859
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	392,700,422	389,639,551
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228		
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227	5,690,246	5,576,329
55	Gas Stored Underground - Current (164.1)		8,724,225	7,737,939
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		51,719,559	49,533,450
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)		170,373,000	163,406,000
62	Miscellaneous Current and Accrued Assets (174)		53,810,690	108,761,676
63	Derivative Instrument Assets (175)		9,863,534	18,787,352
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		2,213,042	3,241,744

65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		1,155,987,210	1,182,444,746
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		52,169,697	44,976,373
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	38,619	131,271
72	Other Regulatory Assets (182.3)	232	889,900,707	713,969,894
73	Prelim. Survey and Investigation Charges (Electric) (183)		31,257,835	17,036,163
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	7,659,608	5,976,466
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		41,935,683	44,504,787
82	Accumulated Deferred Income Taxes (190)	234	514,894,869	232,770,642
83	Unrecovered Purchased Gas Costs (191)		148,491	
84	Total Deferred Debits (lines 69 through 83)		1,538,005,509	1,059,365,596
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		22,090,549,714	19,779,853,537

Name of Respondent: Union Electric Company		This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)					
Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)	
1	PROPRIETARY CAPITAL				
2	Common Stock Issued (201)	250	510,619,170	510,619,170	
3	Preferred Stock Issued (204)	250	80,759,500	80,759,500	
4	Capital Stock Subscribed (202, 205)				
5	Stock Liability for Conversion (203, 206)				
6	Premium on Capital Stock (207)		712,546,956	712,546,956	
7	Other Paid-In Capital (208-211)	253	2,488,544,131	2,012,787,430	
8	Installments Received on Capital Stock (212)	252			
9	(Less) Discount on Capital Stock (213)	254			
10	(Less) Capital Stock Expense (214)	254b			
11	Retained Earnings (215, 215.1, 216)	118	4,206,500,930	3,646,565,225	
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	(1,052,747)		
13	(Less) Reacquired Capital Stock (217)	250			
14	Noncorporate Proprietorship (Non-major only) (218)				
15	Accumulated Other Comprehensive Income (219)	122(a)(b)			
16	Total Proprietary Capital (lines 2 through 15)		7,997,917,940	6,963,278,281	
17	LONG-TERM DEBT				
18	Bonds (221)	256	7,291,525,000	6,399,000,000	
19	(Less) Reacquired Bonds (222)	256			
20	Advances from Associated Companies (223)	256	57,475,000		
21	Other Long-Term Debt (224)	256			
22	Unamortized Premium on Long-Term Debt (225)				
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		16,303,184	12,625,901	
24	Total Long-Term Debt (lines 18 through 23)		7,332,696,816	6,386,374,099	
25	OTHER NONCURRENT LIABILITIES				
26	Obligations Under Capital Leases - Noncurrent (227)		64,653,463	4,805,064	
27	Accumulated Provision for Property Insurance (228.1)				
28	Accumulated Provision for Injuries and Damages (228.2)		17,357,710	15,464,570	
29	Accumulated Provision for Pensions and Benefits (228.3)		8,876,000	14,059,000	

30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)		861,575	652,034
32	Long-Term Portion of Derivative Instrument Liabilities		7,726,808	10,478,866
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		823,258,490	787,046,161
35	Total Other Noncurrent Liabilities (lines 26 through 34)		922,734,046	832,505,695
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)			170,000,000
38	Accounts Payable (232)		590,813,048	579,719,952
39	Notes Payable to Associated Companies (233)			305,450,000
40	Accounts Payable to Associated Companies (234)		163,908,303	52,834,901
41	Customer Deposits (235)		41,929,699	35,288,478
42	Taxes Accrued (236)	262	29,273,180	27,717,112
43	Interest Accrued (237)		87,095,649	69,109,367
44	Dividends Declared (238)		855,044	855,044
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		5,305,721	5,804,000
48	Miscellaneous Current and Accrued Liabilities (242)		163,254,399	87,070,429
49	Obligations Under Capital Leases-Current (243)		13,891,665	6,140,714
50	Derivative Instrument Liabilities (244)		14,773,455	24,640,767
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		7,726,808	10,478,866
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,093,373,355	1,354,151,898
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		3,514,074	2,196,932
57	Accumulated Deferred Investment Tax Credits (255)	266	230,011,543	25,763,326
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	30,497,889	17,129,432
60	Other Regulatory Liabilities (254)	278	2,092,148,627	1,869,923,691
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	53,088,953	77,330,585
63	Accum. Deferred Income Taxes-Other Property (282)		2,184,668,767	2,091,066,472

64	Accum. Deferred Income Taxes-Other (283)		149,897,704	160,133,126
65	Total Deferred Credits (lines 56 through 64)		4,743,827,557	4,243,543,564
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		22,090,549,714	19,779,853,537

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: ObligationsUnderCapitalLeaseNoncurrent Amounts in account 227 represent capitalized operating leases.
(b) Concept: ObligationsUnderCapitalLeasesCurrent Amounts in account 243 represent capitalized operating leases.

24	Accretion Expense (411.10)									
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		3,229,009,394	3,069,437,229			3,093,585,377	2,915,665,285	135,424,017	153,771
27	Net Util Oper Inc (Enter Tot line 2 less 25)		746,560,670	739,723,581			735,423,656	727,886,732	11,137,014	11,836
28	Other Income and Deductions									
29	Other Income									
30	Nonutility Operating Income									
31	Revenues From Merchandising, Jobbing and Contract Work (415)		21,354							
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)									
33	Revenues From Nonutility Operations (417)									
34	(Less) Expenses of Nonutility Operations (417.1)		202,392	14,146						
35	Nonoperating Rental Income (418)		(25,392)	(47,055)						
36	Equity in Earnings of Subsidiary Companies (418.1)	119	(1,052,747)							
37	Interest and Dividend Income (419)		7,987,048	11,389,186						
38	Allowance for Other Funds Used During Construction (419.1)		58,193,576	30,248,783						
39	Miscellaneous Nonoperating Income (421)		2,676,289	1,352,167						
40	Gain on Disposition of Property (421.1)		241,313	47,931						

74	(Less) Extraordinary Deductions (435)									
75	Net Extraordinary Items (Total of line 73 less line 74)									
76	Income Taxes-Federal and Other (409.3)	262	0							
77	Extraordinary Items After Taxes (line 75 less line 76)									
78	Net Income (Total of line 71 and 77)		562,303,136	548,817,504						

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STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		3,646,565,225	3,111,167,899
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		563,355,883	548,817,504
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
23.1	See footnote		(a)(3,420,178)	(3,420,178)
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		(3,420,178)	(3,420,178)
30	Dividends Declared-Common Stock (Account 438)			
30.1				(10,000,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			(10,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		4,206,500,930	3,646,565,225
39	APPROPRIATED RETAINED EARNINGS (Account 215)			

45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		4,206,500,930	3,646,565,225
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)		(1,052,747)	
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)		(1,052,747)	

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FOOTNOTE DATA

(a) Concept: DividendsDeclaredPreferredStock

Total Dividends Declared - Preferred Stock (Account 437)

Account	Current Year	Prior Year
\$4.50 Series	\$ 961,178	\$ 961,178
\$4.56 Series	912,000	912,000
\$4.00 Series	600,000	600,000
\$3.50 Series	455,000	455,000
\$4.30 Series	172,000	172,000
\$3.70 Series	148,000	148,000
\$4.75 Series	95,000	95,000
\$5.50 Series A	77,000	77,000
	\$ 3,420,178	\$ 3,420,178

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STATEMENT OF CASH FLOWS

- Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
- Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
- Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
- Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	562,303,136	548,817,504
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	811,413,132	794,949,967
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Debt Issue Costs	7,128,960	6,742,473
5.2	Amortization of Nuclear Fuel	80,366,750	67,501,388
5.3	Amortization of Operating Leases	8,077,104	6,764,007
5.4	Other Noncash Adjustment	63,276,455	654,335
8	Deferred Income Taxes (Net)	(140,328,857)	31,222,539
9	Investment Tax Credit Adjustment (Net)	(2,779,380)	(3,424,043)
10	Net (Increase) Decrease in Receivables	(12,355,933)	47,675,883
11	Net (Increase) Decrease in Inventory	(7,644,367)	(74,206,246)
12	Net (Increase) Decrease in Allowances Inventory		82,828
13	Net Increase (Decrease) in Payables and Accrued Expenses	215,857,477	(8,865,177)
14	Net (Increase) Decrease in Other Regulatory Assets	(18,558,057)	(72,608,642)
15	Net Increase (Decrease) in Other Regulatory Liabilities	78,946,116	30,698,108
16	(Less) Allowance for Other Funds Used During Construction	58,193,576	30,248,783
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):		
18.2	Net (Increase) Decrease in Other Assets	(29,079,851)	81,389,835
18.3	Net Increase (Decrease) in Other Liabilities	(25,568,367)	(67,603,120)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	1,532,860,742	1,359,542,856
24	Cash Flows from Investment Activities:		

25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(2,806,772,454)	(1,801,892,098)
27	Gross Additions to Nuclear Fuel	(98,838,879)	(177,954,427)
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	(58,193,576)	(30,248,783)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
31.2	(Increase) Decrease in money pool advances		
31.3	Insurance Proceeds Related to Energy Center Outage		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(2,847,417,757)	(1,949,597,742)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	180,386	3,639
39	Investments in and Advances to Assoc. and Subsidiary Companies	(42,775,000)	
40	Contributions and Advances from Assoc. and Subsidiary Companies	465,739,969	
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)	(768,669,162)	(346,775,042)
45	Proceeds from Sales of Investment Securities (a)	742,880,677	322,581,578
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Proceeds from Investment - Peno Creek		
53.2	Other (provide details in footnote):		
53.3	Purchase of Bonds		
53.4	Proceeds from Sale of Remarketed Bonds		
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(2,450,060,887)	(1,973,787,567)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	1,295,324,000	498,970,000

62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other (provide details in footnote):		
64.2	Capital Contribution from Parent	475,756,701	
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Other (provide details in footnote):		
67.2	Contributions and Advances from Associated and Subsidiary Companies (a)		305,450,000
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,771,080,701	804,420,000
72	Payments for Retirement of:		
73	Long-term Debt (b)	(350,000,000)	
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):	(15,195,891)	(9,852,068)
76.2	Capital Issuance Costs	(10,812,474)	(7,268,684)
76.3	Contributions and Advances from Associated and Subsidiary Companies (a)	(305,450,000)	
78	Net Decrease in Short-Term Debt (c)	(169,067,073)	(159,742,558)
80	Dividends on Preferred Stock	(3,420,178)	(3,420,178)
81	Dividends on Common Stock		(10,000,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	917,135,085	614,136,512
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	(65,060)	(108,199)
88	Cash and Cash Equivalents at Beginning of Period	122,764	230,963
90	Cash and Cash Equivalents at End of Period	57,704	122,764

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FOOTNOTE DATA

- (a) Concept: ProceedsFromDisposalOfNoncurrentAssets

Applies to line 37, columns (b) and (c):
Proceeds from sales of properties.
- (b) Concept: PurchaseOfInvestmentSecurities

Applies to lines 44 and 45, columns (b) and (c):
Nuclear Decommissioning Trust Fund.
- (c) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Applies to line 76.1, columns (b) and (c):
Payments related to renewable energy centers.

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

AMEREN CORPORATION (Consolidated)
UNION ELECTRIC COMPANY (d/b/a Ameren Missouri)
AMEREN ILLINOIS COMPANY (d/b/a Ameren Illinois)

COMBINED NOTES TO FINANCIAL STATEMENTS

(Unaudited)

December 31, 2024

(These notes relate to all of the Ameren SEC registrants, including the FERC Form 1 respondent Union Electric Company)

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

Accounting policies for regulated operations are in accordance with those prescribed by the regulatory authorities having jurisdiction, principally the Missouri Public Service Commission (MoPSC), the Federal Energy Regulatory Commission (FERC) and the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 2005 (PUHCA). The accompanying financial statements have been prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts (USOA) and accounting releases, which require certain differences from accounting principles generally accepted in the United States (GAAP). The differences between the accounting requirements of FERC and GAAP include, but are not limited to, the following:

- Balance sheet presentation of asset removal costs, accumulated deferred income taxes, uncertain tax positions, property, plant and equipment, regulatory assets, and regulatory liabilities.
- Income statement classification of certain items between operating revenues and expenses and nonoperating revenues and expenses, including the non-service cost or income components of the net periodic benefit cost related to pensions and other postretirement benefit plans.
- Cash flow statement classification for restricted cash and implementation costs for cloud computing.

In accordance with FERC Form 1 Instructions, these notes to the financial statements are primarily a replica of the notes to the financial statements included in Ameren's published annual report filed on Form 10-K with the SEC pursuant to the Securities Exchange Act of 1934, which are prepared in accordance with GAAP. Ameren's Form 10-K is a combined filing including Ameren, Union Electric Company and Ameren Illinois Company. Please refer to the "Glossary of Terms and Abbreviations" within Ameren's Form 10-K in conjunction with these notes.

General

Ameren, headquartered in St. Louis, Missouri, is a public utility holding company whose primary assets are its equity interests in its subsidiaries. Ameren's subsidiaries are separate, independent legal entities with separate businesses, assets, and liabilities. Dividends on Ameren's common stock and the payment of expenses by Ameren depend on distributions made to it by its subsidiaries. Ameren's principal subsidiaries are listed below. Ameren also has other subsidiaries that conduct other activities, such as providing shared services.

- Union Electric Company, doing business as Ameren Missouri, operates a rate-regulated electric generation, transmission, and distribution business and a rate-regulated natural gas distribution business in Missouri. Ameren Missouri was incorporated in Missouri in 1922 and is successor to a number of companies, the oldest of which was organized in 1881. It is the largest electric utility in the state of Missouri. It supplies electric and natural gas service to a 24,000-square-mile area in central and eastern Missouri, which includes the Greater St. Louis area. Ameren Missouri supplies electric service to 1.3 million customers and natural gas service to 0.1 million customers.
- Ameren Illinois Company, doing business as Ameren Illinois, operates rate-regulated electric transmission, electric distribution, and natural gas distribution businesses in Illinois. Ameren Illinois was incorporated in Illinois in 1923 and is the successor to a number of companies, the oldest of which was organized in 1902. Ameren Illinois supplies electric and natural gas utility service to a 43,700 square mile area in central and southern Illinois. Ameren Illinois supplies electric service to 1.2 million customers and natural gas service to 0.8 million customers.
- ATXI operates a FERC rate-regulated electric transmission business in the MISO. ATXI was incorporated in Illinois in 2006. ATXI operates, among other assets, the Spoon River, Mark Twain, and Illinois Rivers transmission lines.

Ameren's and Ameren Missouri's financial statements are prepared on a consolidated basis and therefore include the accounts of their majority-owned subsidiaries. All intercompany transactions have been eliminated. Ameren Illinois has no subsidiaries. All tabular dollar amounts are in millions, unless otherwise indicated.

Our accounting policies conform to GAAP. Our financial statements reflect all adjustments (which include normal, recurring adjustments) that are necessary, in our opinion, for a fair presentation of our results. The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions. Such estimates and assumptions affect reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the dates of financial statements, and the reported amounts of revenues and expenses during the reported periods. Actual results could differ from those estimates.

Regulation

Our customer rates are regulated by the MoPSC, the ICC, and the FERC. We defer certain costs as assets pursuant to actions of rate regulators or because of expectations that we will be able to recover such costs in future rates charged to customers. We also defer certain amounts as liabilities pursuant to actions of rate regulators or based on the expectation that such amounts will be refunded to customers in future rates. Regulatory assets and liabilities are amortized consistent with the period of expected regulatory treatment. See Note 2 – Rate and Regulatory Matters for additional information on our regulatory frameworks, regulatory recovery mechanisms, and regulatory assets and liabilities recorded at December 31, 2024 and 2023.

We periodically assess the recoverability of our regulatory assets and probability of refund of our regulatory liabilities. Regulatory assets are charged to earnings when it is no longer probable that such amounts will be recovered through future revenues. To the extent that refunds to customers related to regulatory liabilities are eliminated by the regulator or are no longer probable, the amounts are credited to earnings.

Cash, Cash Equivalents, and Restricted Cash

Cash and cash equivalents include short-term, highly liquid investments purchased with an original maturity of three months or less. Cash and cash equivalents subject to legal or contractual restrictions and not readily available for use for general corporate purposes are classified as restricted cash. See Note 15 – Supplemental Information for a reconciliation of cash, cash equivalents, and restricted cash reported within the balance sheets and the statements of cash flows.

Allowance for Doubtful Accounts Receivable

The allowance for doubtful accounts represents our estimate of existing accounts receivable that will ultimately be uncollectible. The allowance is calculated by applying estimated loss factors to various classes of outstanding receivables, including unbilled revenue. The loss factors used to estimate uncollectible accounts are based upon both historical collections experience and management's estimate of future collections success given the existing and anticipated future collections environment. Ameren Illinois has had debt riders that adjust rates for net write-offs of customer accounts receivable above or below those being collected in rates.

Inventories

Inventories are recorded at the lower of weighted-average cost or net realizable value. Inventories are charged to expense or capitalized to property, plant and equipment when issued, as appropriate, using the weighted-average cost method. See Note 15 – Supplemental Information for the components of inventories.

Property, Plant, and Equipment, Net

We capitalize the cost of additions to, and betterments of, units of property, plant, and equipment. The cost includes labor, material, applicable taxes, and overhead. An allowance for funds used during construction, as discussed below, is also capitalized as a cost of our rate-regulated assets. Maintenance expenses related to scheduled Callaway nuclear refueling and maintenance outages are deferred and amortized over the number of expected months until the completion of the next refueling outage, which historically has been approximately 18 months. Other maintenance expenditures are expensed as incurred. When units of depreciable property are retired, the original costs, and the associated removal cost, net of salvage, are charged to accumulated depreciation. If environmental expenditures are related to assets currently in use, as in the case of the installation of pollution control equipment, the cost is capitalized and depreciated over the expected life of the asset. See Asset Retirement Obligations and Removal Costs section below and Note 3 – Property, Plant, and Equipment, Net for additional information.

Ameren Missouri's cost of nuclear fuel is capitalized as a part of "Property, Plant, and Equipment, Net" on Ameren and Ameren Missouri's balance sheets and then amortized to "Operating Expenses – Fuel and purchased power" in their respective statements of income on a unit-of-production basis. Nuclear fuel amortization is reflected as a part of "Amortization of nuclear fuel" on their respective statements of cash flow.

Plant to be Abandoned, Net

When it becomes probable an asset will be retired significantly in advance of its previously expected useful life and in the near term, the Ameren Companies must assess the probability of recovery of the remaining net book value of the asset to be abandoned. We recognize a loss on abandonment when it becomes probable that all or part of the cost of an asset, including a return at the applicable WACC, will be disallowed from recovery either through customer rates or through the issuance of securitized utility tariff bonds and such amount is reasonably estimable. An abandonment loss, if any, would equal the difference between the remaining net book value of the asset and the present value of the expected future cash flows. If the asset is still in service, the net book value is classified as plant to be abandoned, net, within "Property, Plant, and Equipment, Net" on the balance sheet. The net book value will be classified as a regulatory asset on the balance sheet when the asset is no longer in service or as required by a rate order.

In relation to the NSR and Clean Air Act litigation discussed in Note 14 – Commitments and Contingencies, Ameren Missouri retired the Rush Island Energy Center on October 15, 2024. In June 2024, the MoPSC issued a financing order authorizing the issuance of securitized utility tariff bonds by AMF to finance costs related to the accelerated retirement of the Rush Island Energy Center. In December 2024, AMF issued \$476 million of securitized utility tariff bonds. As a result of the financing order and the issuance of the securitized utility tariff bonds, Ameren Missouri concluded no abandonment loss was required for the Rush Island Energy Center and classified the remaining net book value as a regulatory asset as of December 31, 2024. See Variable Interest Entities below, Note 2 – Rate and Regulatory Matters, and Note 5 – Long-term Debt and Equity Financings for additional information on Ameren Missouri's securitization of the Rush Island Energy Center's costs. As of December 31, 2023, Ameren and Ameren Missouri determined that the Rush Island Energy Center met the criteria to be considered probable of abandonment and classified its remaining net book value as plant to be abandoned, net, within "Property, Plant, and Equipment, Net" on Ameren's and Ameren Missouri's balance sheets. See Note 3 – Property, Plant, and Equipment, Net for our plant to be abandoned balance as of December 31, 2023.

Depreciation

Depreciation is provided over the estimated lives of the various classes of depreciable tangible property by applying composite rates on a straight-line basis to the cost basis of such property. The composite rates include a provision for the estimated removal cost of property, plant, and equipment retired from service, net of salvage. See Asset Retirement Obligation and Removal Costs section below for additional information. The provision for depreciation for the Ameren Companies in 2024, 2023, and 2022 ranged from 3% to 4% of the average depreciable cost. See Note 3 – Property, Plant, and Equipment, Net for additional information on estimated depreciable lives.

Allowance for Funds Used During Construction

As a part of "Property, Plant, and Equipment, Net" on the balance sheet, we capitalize allowance for funds used during construction, which is the cost of borrowed funds and the cost of equity funds (preferred and common shareholders' equity) applicable to eligible rate-regulated construction work in progress, in accordance with the utility industry's accounting practice and GAAP. The amount of allowance for funds used during construction is calculated using a FERC-prescribed formula based on a rate, which incorporates the average cost of short-term debt, the average cost of long-term debt, and the cost of equity funds. The portion attributable to borrowed funds is recorded as a reduction of "Interest Charges" on the statements of income. The portion attributable to equity funds is recorded within "Other Income, Net" on the statements of income. This accounting practice offsets the effect on earnings of the cost of financing during construction. See Note 15 – Supplemental Information for the amount of allowance for funds used during construction capitalized and the average rate applied to eligible construction work in progress.

Allowance for funds used during construction does not represent a current source of cash funds. Under accepted ratemaking practice, cash recovery of allowance for funds used during construction and other construction costs occurs when completed projects are placed in service and reflected in customer rates.

Goodwill

Goodwill represents the excess of the purchase price of an acquisition over the fair value of the net assets acquired. Ameren and Ameren Illinois had goodwill of \$411 million at December 31, 2024 and 2023. Ameren has four reporting units: Ameren Missouri, Ameren Illinois Electric Distribution, Ameren Illinois Natural Gas, and Ameren Transmission. Ameren Illinois has three reporting units:

Ameren Illinois Electric Distribution, Ameren Illinois Natural Gas, and Ameren Illinois Transmission. Ameren Illinois Electric Distribution, Ameren Illinois Natural Gas, and Ameren Illinois Transmission had goodwill of \$238 million, \$80 million, and \$93 million, respectively, at December 31, 2024 and 2023. The Ameren Transmission reporting unit had the same \$93 million of goodwill as the Ameren Illinois Transmission reporting unit at December 31, 2024 and 2023.

Ameren and Ameren Illinois evaluate goodwill for impairment in each of their reporting units as of October 31 each year, or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of their reporting units below their carrying amounts. To determine whether the fair value of a reporting unit is more likely than not greater than its carrying amount, Ameren and Ameren Illinois can elect to perform either a qualitative assessment or to bypass the qualitative assessment and perform a quantitative test.

Ameren and Ameren Illinois elected to perform a qualitative assessment for their annual goodwill impairment test conducted as of October 31, 2024. As part of this qualitative assessment, Ameren and Ameren Illinois evaluated, among other things, macroeconomic conditions, industry and market considerations such as observable industry market multiples, regulatory frameworks, cost factors, overall financial performance, and entity-specific events. The results of Ameren's and Ameren Illinois' qualitative assessment indicated that it was more likely than not that the fair value of each reporting unit exceeded its carrying value as of October 31, 2024, resulting in no impairment of Ameren's or Ameren Illinois' goodwill.

Impairment of Long-lived Assets

We evaluate long-lived assets classified as held and used for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Whether an impairment has occurred is determined by comparing the estimated undiscounted cash flows attributable to the assets to the carrying value of the assets. If the carrying value exceeds the undiscounted cash flows, we recognize an impairment charge equal to the amount by which the carrying value exceeds the estimated fair value of the assets. In the period in which we determine that an asset meets held for sale criteria, we record an impairment charge to the extent the book value exceeds its estimated fair value less cost to sell. We did not identify any events or changes in circumstances that indicated that the carrying value of material long-lived assets may not be recoverable in 2024, 2023, or 2022.

Variable Interest Entities

Variable Interest Entities that are Consolidated

AMF was formed in 2024, for the purpose of issuing and servicing securitized utility tariff bonds related to costs for the accelerated retirement of the Rush Island Energy Center. Ameren Missouri is the primary beneficiary of this entity because it has the power to direct the activities that most significantly impact the economic performance of the company, as well as the obligation to absorb losses or the right to receive benefits from the company. The entity is considered a variable interest entity primarily because its equity capitalization is insufficient to support its operations. The entity's primary assets and liabilities are comprised of regulatory assets related to the unrecovered net plant balance associated with the facility, among other costs, and long-term debt. Ameren and Ameren Missouri consolidate AMF, which Ameren Missouri wholly owns, and both manages and controls the entity's operating activities. For additional information on the securitization of the Rush Island Energy Center costs, see Note 2 – Rate and Regulatory Matters. For additional information on the securitized tariff bond issuance, see Note 5 – Long-term Debt and Equity Financings.

The following table presents the carrying values of AMF's assets and liabilities included on Ameren's and Ameren Missouri's consolidated balance sheets as of December 31, 2024:

	2024
Other current assets ^(a)	\$ 2
Noncurrent regulatory assets ^(a)	465
Current maturities of long term debt ^(b)	17
Interest accrued ^(b)	1
Long-term debt, net ^(b)	448

- (a) Assets may be used only to meet AMF's obligations and commitments.
(b) The securitized tariff bondholders have no recourse to Ameren Missouri.

Variable Interest Entities that are not Consolidated

As of December 31, 2024 and 2023, Ameren had unconsolidated variable interests in various equity method investments, primarily to advance clean and resilient energy technologies, totaling \$74 million and \$73 million, respectively, included in "Other assets" on Ameren's consolidated balance sheet. Any earnings or losses related to these investments are included in "Other Income, Net" on Ameren's consolidated statement of income and comprehensive income. Ameren is not the primary beneficiary of these investments because it does not have the power to direct matters that most significantly affect the activities of these variable interest entities. As of December 31, 2024, the maximum exposure to loss related to these variable interest entities is limited to the investment in these partnerships of \$74 million plus associated outstanding funding commitments of \$35 million.

Environmental Costs

Liabilities for environmental costs are recorded on an undiscounted basis when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Costs are expensed or deferred as a regulatory asset when it is expected that the costs will be recovered from customers in future rates. See Note 14 – Commitments and Contingencies for additional information on liabilities for environmental costs.

Asset Retirement Obligations and Removal Costs

We record the estimated fair value of legal obligations associated with the retirement of tangible long-lived assets in the period in which the liabilities are incurred and capitalize a corresponding amount as part of the book value of the related long-lived asset. In subsequent periods, we adjust AROs for accretion and changes in the estimated fair values of the obligations, with a corresponding increase or decrease in the asset book value for the fair value changes. Asset book values, reflected within "Property, Plant, and Equipment, Net" on the balance sheet, are depreciated over the remaining useful life of the related asset. Depreciation is deferred as a regulatory balance. The depreciation of the asset book values at Ameren Missouri was \$2 million, \$9 million, and \$7 million for the years ended December 31, 2024, 2023, and 2022, respectively, which was deferred as a reduction to the net regulatory liability. The net regulatory liability also reflects a deferral for the nuclear decommissioning trust fund balance for the Callaway Energy Center. The depreciation deferred to the regulatory asset at Ameren Illinois was immaterial in each respective period. Uncertainties as to the probability, timing, or amount of cash expenditures associated with AROs affect our estimates of fair value. Ameren and Ameren Missouri have recorded AROs for retirement costs associated with decommissioning of Ameren Missouri's Callaway and wind renewable energy centers, certain Ameren Missouri solar energy centers, CCR facilities, and river structures at certain energy centers used for unloading coal and circulating water systems. Additionally, Ameren, Ameren Missouri, and Ameren Illinois have recorded AROs for retirement costs associated with asbestos removal and the disposal of certain transformers. See Note 15 – Supplemental Information for a reconciliation of the beginning and ending carrying amounts of AROs.

Estimated funds collected from customers to pay for the future removal cost of property, plant, and equipment retired from service, net of salvage, represent a cost of removal regulatory liability for GAAP reporting purposes. See the cost of removal regulatory liability balance in Note 2 – Rate and Regulatory Matters.

COLI

Ameren (parent) and Ameren Illinois have COLI, which is recorded at the net cash surrender value. The net cash surrender value is the amount that can be realized under the insurance policies at the balance sheet date. As of December 31, 2024, the cash surrender value of COLI at Ameren and Ameren Illinois was \$260 million (December 31, 2023 – \$248 million) and \$118 million (December 31, 2023 – \$111 million), respectively, while total borrowings against the policies were \$110 million (December 31, 2023 – \$104 million) at both Ameren and Ameren Illinois. Ameren and Ameren Illinois have the right to offset the borrowings against the cash surrender value of the policies and, consequently, present the net asset in "Other assets" on their respective balance sheets. The net cash surrender value of Ameren's COLI is affected by the investment performance of a separate account in which Ameren holds a beneficial interest.

Operating Revenues

We record revenues from contracts with customers for various electric and natural gas services, which primarily consist of retail distribution, electric transmission, and off-system arrangements. When more than one performance obligation exists in a contract, the consideration under the contract is allocated to the performance obligations based on the relative standalone selling price.

Electric and natural gas retail distribution revenues are earned when the commodity is delivered to our customers. We accrue an estimate of electric and natural gas retail distribution revenues for service provided but unbilled at the end of each accounting period. Electric transmission revenues are earned as electric transmission services are provided. Off-system revenues are primarily

comprised of MISO revenues and wholesale bilateral revenues. MISO revenues include the sale of electricity, capacity, and ancillary services. Wholesale bilateral revenues include the sale of electricity and capacity. MISO-related electricity and wholesale bilateral electricity revenues are earned as electricity is delivered. Capacity and ancillary service revenues are earned as services are provided.

Retail distribution, electric transmission, and off-system revenues, including the underlying components described above, represent a series of goods or services that are substantially the same and have the same pattern of transfer over time to our customers. Revenues from contracts with customers are equal to the amounts billed and our estimate of electric and natural gas retail distribution services provided but unbilled at the end of each accounting period. Customers are billed at least monthly, and payments are due less than one month after goods and/or services are provided. See Note 16 – Segment Information for disaggregated revenue information.

For certain regulatory recovery mechanisms that are alternative revenue programs rather than revenues from contracts with customers for GAAP reporting purposes, we recognize revenues that have been authorized for rate recovery, are objectively determinable and probable of recovery, and are expected to be collected from customers within two years from the end of the year. Our alternative revenue programs include revenue requirement reconciliations, the MEEIA, the RBA, the VBA, and the WNAR. These revenues are subsequently recognized as revenues from contracts with customers when billed, with an offset to alternative revenue program revenues.

As of December 31, 2024 and 2023, our remaining performance obligations were immaterial. The Ameren Companies elected not to disclose the aggregate amount of the transaction price allocated to the performance obligations that are unsatisfied as of the end of the reporting period for contracts with an initial expected term of one year or less.

Accounting for MISO Transactions

MISO-related purchase and sale transactions are recorded by Ameren, Ameren Missouri, and Ameren Illinois using settlement information provided by the MISO. Ameren Missouri records these purchase and sale transactions on a net hourly position. Ameren Missouri records net purchases in a single hour in “Operating Expenses – Fuel and purchased power” and net sales in a single hour in “Operating Revenues – Electric” in its statement of income. Ameren Illinois records net purchases in “Operating Expenses – Fuel and purchased power” in its statement of income to reflect all of its MISO transactions relating to the procurement of power for its customers.

Stock-based Compensation

Stock-based compensation cost is measured at the grant date based on the fair value of the award, net of an assumed forfeiture rate. Ameren recognizes as compensation expense the estimated fair value of stock-based compensation on a straight-line basis over the requisite vesting period. To the extent that actual forfeitures differ from estimated forfeitures, such differences are accounted for as an adjustment to compensation expense and recorded in the period that estimates are revised. Compensation cost is ultimately recognized only for awards for which the requisite service was provided. See Note 11 – Stock-based Compensation for additional information.

Unamortized Debt Discounts, Premiums, and Issuance Costs

Long-term debt discounts, premiums, and issuance costs are amortized over the lives of the related issuances. Credit agreement fees are amortized over the term of the agreement.

Income Taxes

Ameren uses an asset and liability approach for its financial accounting and reporting of income taxes. Deferred tax assets and liabilities are recognized for transactions that are treated differently for financial reporting and income tax return purposes. These deferred tax assets and liabilities are based on statutory tax rates. In accordance with USOA, we report deferred income tax balances arising from temporary differences in Accounts 190, 282, and 283 as appropriate, which differs from the net presentation required by GAAP.

We expect that regulators will reduce future revenues for deferred tax liabilities that were initially recorded at rates in excess of the current statutory rate. Therefore, reductions in certain excess deferred tax liabilities that were recorded because of decreases in the statutory rate have been credited to a regulatory liability. A regulatory asset has been established to recognize the probable recovery through future customer rates of tax benefits related to the equity component of allowance for funds used during construction, as well as the effects of tax rate increases. To the extent deferred tax balances are included in rate base, the revaluation of deferred taxes caused by a change in the statutory rate is recorded as a regulatory asset or liability on the balance sheet and will be collected from, or refunded to, customers. For deferred tax balances not included in rate base, the revaluation of deferred taxes caused by a change in the statutory rate is recorded as an adjustment to income tax expense on the income statement.

Tax credits other than investment tax credits are recognized as a reduction to income tax expense when earned. The benefits for investment tax credits not transferred under the IRA are amortized over the book depreciable lives of the related property. For production and other tax credits otherwise eligible to be recognized when earned and for investment tax credits transferred under the IRA, Ameren considers the impact of rate regulation to determine if these credits and related adjustments should be deferred as regulatory liabilities. See Note 2 – Rate and Regulatory Matters for additional information on Ameren Missouri’s production and investment tax credit tracker and the RESRAM.

Ameren Missouri, Ameren Illinois, and all the other Ameren subsidiary companies are parties to a tax allocation agreement with Ameren (parent) that provides for the allocation of consolidated tax liabilities. The tax allocation agreement specifies that each subsidiary be allocated an amount of tax using a stand-alone calculation ratio to the total amount of tax owed by the consolidated group. Any net benefit attributable to Ameren (parent) is reallocated to the other subsidiaries. This reallocation is treated as a capital contribution to the subsidiary receiving the benefit. See Note 13 – Related-party Transactions for information regarding capital contributions under the tax allocation agreement.

NOTE 2 – RATE AND REGULATORY MATTERS

Below is a summary of our regulatory frameworks and significant regulatory proceedings and related lawsuits. We are unable to predict the ultimate outcome of these matters, the timing of final decisions of the various agencies and courts, or the effect on our results of operations, financial position, or liquidity.

Regulatory Frameworks

The following table presents the regulatory frameworks and significant regulatory recovery mechanisms for each of Ameren’s rate-regulated businesses, which are discussed in more detail below:

	Ameren Missouri	Ameren Illinois' electric distribution business	Ameren Illinois' natural gas delivery business	Ameren Illinois' and ATXI's electric transmission businesses
Regulatory framework	<ul style="list-style-type: none"> Historical test year ratemaking Natural gas revenues for residential customers adjusted for sales volume deviations resulting from weather through the WNAR 	<ul style="list-style-type: none"> MYRP Initial rates based on future test years Revenues decoupled from sales volumes and wholesale and miscellaneous revenues through the RBA 	<ul style="list-style-type: none"> Future test year ratemaking Revenues for residential and small nonresidential customers decoupled from sales volumes through the VBA 	<ul style="list-style-type: none"> Formula ratemaking Initial rates based on future test year Revenues decoupled from sales volumes
Regulatory mechanisms	<ul style="list-style-type: none"> PISA <p>Riders:</p> <ul style="list-style-type: none"> RESRAM FAC Rush Island Securitization MEEIA PGA WNAR <p>Trackers:</p> <ul style="list-style-type: none"> Pension and postretirement benefit costs Certain excess deferred income taxes Renewable energy standard costs Property taxes Production and investment tax credits or proceeds from the sale of certain tax credits allowed under the IRA 	<ul style="list-style-type: none"> Electric distribution service and energy-efficiency revenue requirement reconciliation adjustments^(a) <p>Riders:</p> <ul style="list-style-type: none"> RBA Power procurement Transmission services Renewable energy credit compliance Zero emission credits Customer generation rebate program costs Certain environmental costs Bad debt write-offs Costs of certain asbestos-related claims 	<p>Riders:</p> <ul style="list-style-type: none"> PGA VBA Energy-efficiency program costs Certain environmental costs Bad debt write-offs Invested capital taxes 	<ul style="list-style-type: none"> Revenue requirement reconciliation adjustment

(a) Reconciliation adjustments under an MYRP are subject to a reconciliation cap which limits annual adjustment to 105%. See below for additional information regarding the reconciliation cap.

Missouri

The MoPSC regulates rates and other matters for Ameren Missouri's electric service and natural gas distribution businesses. The rates Ameren Missouri charges customers for these services are established in a traditional regulatory rate review, which takes up to 11 months to complete, based on a historical test year and the revenue requirement established in the review.

Ameren Missouri has recovery mechanisms, including the RESRAM, FAC, MEEIA, PGA, and WNAR, as well as a rider related to the securitization of the Rush Island Energy Center, that allow customer rates to be adjusted without a traditional regulatory rate review. These riders, along with the PISA, each described in more detail below, partially mitigate the effects of regulatory lag. Ameren Missouri also employs other recovery mechanisms, including a renewable energy standard cost tracker, as well as electric and natural gas trackers for certain excess deferred income taxes, property taxes, and pension and postretirement benefit costs. Each of these trackers allows Ameren Missouri to defer the difference between actual costs incurred and costs included in customer rates as a regulatory asset or regulatory liability, with the difference expected to be reflected in base rates in a subsequent MoPSC rate order. Ameren Missouri also employs a tracker for the utilization of production and investment tax credits or proceeds from the sale of such tax credits allowed under the IRA. Production and investment tax credits produced by renewable energy centers that support compliance with the state of Missouri's renewable energy standard, such as the High Prairie, Atchison, and Huck Finn energy centers, are not eligible for tracking under this mechanism as they are included in the RESRAM. Ameren Missouri's cost recovery under any of its recovery mechanisms is subject to MoPSC prudence reviews.

The PISA permits Ameren Missouri to defer and recover 85% of the depreciation expense for investments in qualifying property, plant, and equipment placed in service and not included in base rates. Investments not eligible for recovery under the PISA include amounts related to new nuclear and natural gas generating units and service to new customer premises. Additionally, the PISA permits Ameren Missouri to earn a return at the applicable WACC on 85% of rate base that incorporates those qualifying investments, as well as changes in total accumulated depreciation excluding retirements and plant-related deferred income taxes since the previous regulatory rate review. The regulatory asset for accumulated PISA deferrals also earns a return at the applicable WACC until added to rate base prospectively. Ameren Missouri recognizes an offset to "Interest Charges" on its consolidated statement of income for its carrying cost of debt relating to each return allowed under the PISA, with the difference between the applicable WACC and its carrying cost of debt recognized in revenues when recovery of PISA deferrals is reflected in customer rates. Approved PISA deferrals are recovered over a period of 20 years following a regulatory rate review. Additionally, under the RESRAM, Ameren Missouri is permitted to recover the 15% of depreciation expense not recovered under the PISA, and earn a return at the applicable WACC for investments in renewable generation plant placed in service to comply with Missouri's renewable energy standard. The RESRAM deferrals are a regulatory asset until they are included in customer rates and collected in a subsequent period. Those investments not eligible for recovery under the PISA and the remaining 15% of certain property, plant, and equipment placed in service, unless eligible for recovery under the RESRAM, remain subject to regulatory lag. As a result of the PISA election, additional provisions of the law apply to Ameren Missouri, including limitations on electric customer rate increases. Pursuant to a Missouri law, Ameren Missouri's PISA election was extended through December 2028 and an additional extension through December 2033 is allowed if requested by Ameren Missouri and approved by the MoPSC, among other things. This law also established a 2.5% annual limit on increases to the electric service revenue requirement used to set customer rates, compared to the revenue requirement established in the immediately preceding rate order, due to the inclusion of incremental PISA deferrals in the revenue requirement. The limitation is effective for revenue requirements approved by the MoPSC after January 1, 2024.

The RESRAM permits Ameren Missouri to recover or refund, through customer rates, the difference between the cost of compliance, net of production and investment tax credits, with Missouri's renewable energy standard and the amount set in base rates. All sales from the High Prairie, Atchison, and Huck Finn energy centers are included in the RESRAM. Customer rates are adjusted for the RESRAM on an annual basis without a traditional regulatory rate review, subject to MoPSC prudence reviews. The difference between actual compliance costs and costs billed to customers in a given period is deferred as a regulatory asset or liability. The deferred amount is either collected from, or refunded to, customers in a subsequent period. RESRAM regulatory assets earn carrying costs at short-term interest rates. The RESRAM permits Ameren Missouri to recover investments in wind generation and other renewables related to compliance with Missouri's renewable energy standard, and earn a return at the applicable WACC on those investments not already provided for in customer rates or any other recovery mechanism, such as the renewable energy standard cost tracker. The renewable energy standard cost tracker allows Ameren Missouri to defer differences between actual costs primarily associated with the Maryland Heights Energy Center and renewable energy credits obtained through a 102-MW power purchase agreement with a wind farm operator, which expired in August 2024, and those costs included in customer rates.

The FAC permits Ameren Missouri to recover or refund, through customer rates, 95% of the variance in net energy costs from the amount set in base rates without a traditional regulatory rate review, subject to MoPSC prudence reviews, with the remaining 5% of changes retained by Ameren Missouri. As such, Ameren Missouri's results of operations are affected by the 5% not recovered or refunded under the FAC. The 95% variance in net energy costs in a given period is deferred as a regulatory asset or liability, and is either collected from, or refunded to, customers in a subsequent period. FAC regulatory assets earn carrying costs at short-term interest rates. Ameren Missouri's base rates for electric service are required to be reset at least every four years to allow for continued use of the FAC.

In June 2024, the MoPSC issued a financing order authorizing the issuance of securitized utility tariff bonds by AMF to finance \$476 million of costs related to the accelerated retirement of the Rush Island Energy Center, which included the remaining unrecovered net plant balance associated with the facility, among other costs. Ameren Missouri will collect the amounts necessary to repay the bonds through a rider over approximately 15 years from the date of the December 2024 bond issuance.

The MEEIA permits Ameren Missouri to recover customer energy-efficiency and demand response program costs, the related lost electric revenues, and any performance incentive through the MEEIA without a traditional regulatory rate review, subject to MoPSC prudence reviews. MEEIA assets earn carrying costs at short-term interest rates.

Ameren Missouri is a member of the MISO, and its transmission rate is calculated in accordance with the MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff. The FERC regulates the rates charged and the terms and conditions for wholesale electric transmission service. The transmission rate update each June is based on Ameren Missouri's actual historical cost from the prior calendar year. This rate is not directly charged to Missouri retail customers because, in Missouri, the revenue requirement used to set bundled retail base rates includes an amount for transmission-related costs and revenues.

The PGA allows Ameren Missouri to recover costs of natural gas purchased on behalf of its customers without a traditional regulatory rate review, subject to MoPSC prudence reviews. These pass-through purchased gas costs do not affect Ameren Missouri's net income, as any change in costs is offset by a corresponding change in revenues. The difference between actual natural gas costs and costs billed to customers in a given period is deferred as a regulatory asset or liability. The deferred amount is either collected from, or refunded to, customers in a subsequent period. PGA regulatory assets earn carrying costs at short-term interest rates.

The WNAR allows Ameren Missouri to adjust natural gas delivery service rates charged to residential customers without a traditional regulatory rate review when deviations from normal weather conditions cause natural gas revenues to vary from the related revenue requirement approved by the MoPSC in the previous regulatory rate review. The impact of deviations from normal weather on natural gas delivery service revenues billed to residential customers in a given period are deferred as a regulatory asset or liability. WNAR regulatory assets earn carrying costs at short-term interest rates. The deferred amount is either collected from, or refunded to, residential customers in a subsequent period.

Illinois

The ICC regulates rates and other matters for Ameren Illinois' electric distribution service and natural gas distribution businesses. Pursuant to the CEJA, Ameren Illinois may elect to establish electric distribution service rates through either an MYRP or a traditional regulatory rate review. See below for additional information regarding the MYRP approved by the ICC, which established rates effective for 2024 through 2027. The rates Ameren Illinois charges customers for natural gas distribution service are established in a traditional regulatory rate review, which takes up to 11 months to complete, based on a future test year and the revenue requirement established in the review.

Ameren Illinois' electric distribution service has cost recovery mechanisms in place that allow customer rates to be adjusted without an MYRP or a traditional regulatory rate review. This includes the RBA, which is described in more detail below, and riders for power procurement and transmission services incurred on behalf of its customers, renewable energy credit compliance, zero emission credits, customer generation rebate program costs, and certain environmental costs, as well as bad debt write-offs and the costs of certain asbestos-related claims not recovered in base rates. These pass-through costs do not affect Ameren Illinois' net income, as any change in costs is offset by a corresponding change in revenues. Ameren Illinois' cost recovery under any of its recovery mechanisms is subject to ICC prudence reviews.

Under the MYRP, Ameren Illinois is allowed to reconcile its actual electric distribution revenue requirement, as adjusted for certain cost variations, to the ICC-approved revenue requirement on an annual basis, subject to a reconciliation cap. The reconciliation cap limits the annual adjustment to 105% of the annual revenue requirement approved by the ICC. Certain variations from forecasted costs are excluded from the reconciliation cap, including those associated with major storms; new business and facility relocations; changes in the timing of certain expenditures or investments into or out of the applicable calendar year; and changes in interest rates, income taxes, taxes other than income taxes, pension and other post-retirement benefits costs, and amortization of certain assets. The reconciliation cap also excludes costs recovered outside of base rates through riders, such as those described above and the electric energy-efficiency rider discussed below, among others. The actual revenue requirement for a particular year incorporates Ameren Illinois' year-end rate base and actual capital structure for such year, provided that the resulting revenue requirement does not exceed the 105% reconciliation cap and the common equity ratio in such capital structure may not exceed that approved by the ICC in the MYRP. Ameren Illinois did not exceed the reconciliation cap for the 2024 revenue requirement, which is subject to final reconciliation and ICC review. Subject to the reconciliation cap, if a given year's actual revenue requirement collected from customers varies from the approved revenue requirement, an adjustment is made to electric operating revenues with an offset to a regulatory asset or liability to reflect that year's actual revenue requirement. The regulatory balance is then collected from, or refunded to, customers within two years from the end of the applicable annual period. Regulatory assets applicable to the MYRP earn a return at the applicable WACC. However, Ameren Illinois recognizes the carrying cost of debt on these regulatory assets in revenue, instead of the applicable WACC, with the difference recognized in revenues when recovery of such regulatory assets is reflected in customer rates. Ameren Illinois' existing riders continue to be effective under the MYRP.

The RBA allows Ameren Illinois to adjust electric distribution service rates charged to customers under an MYRP or a traditional regulatory rate review when electric distribution revenues vary from the related revenue requirement approved by the ICC in the previous MYRP or traditional regulatory rate review. If a given year's actual revenue billed to customers varies from the approved revenue requirement as a result of sales volumes and/or wholesale and miscellaneous revenue, an adjustment is made to electric operating revenues with an offset to a regulatory asset or liability to reflect that year's actual revenue. RBA regulatory assets do not earn carrying costs or a return. The regulatory balance is either collected from, or refunded to, customers within two years from the end of the applicable annual period.

Ameren Illinois used the IEIMA formula framework to establish annual customer electric distribution service rates effective through 2023. Under the framework, Ameren Illinois was allowed to reconcile its revenue requirement for customer rates established through 2023. Ameren Illinois' 2022 and 2023 revenues reflected each year's actual recoverable costs, year-end rate base, and a return at the applicable WACC, with the ROE component based on the annual average of the monthly yields of the 30-year United States Treasury bonds plus 580 basis points. The 2022 revenue requirement reconciliation adjustment was collected from customers in 2024, and the 2023 adjustment will be collected in 2025.

Ameren Illinois' electric customer energy-efficiency rider provides Ameren Illinois' electric distribution service business with recovery of, and return on, energy-efficiency investments. Under formula ratemaking for its electric energy-efficiency investments, the revenue requirements are based on recoverable costs, year-end rate base, and a year-end ratemaking capital structure, and earn a return at the applicable WACC. The ROE component of the applicable WACC is based on the annual average of the monthly yields of the 30-year United States Treasury bonds plus 580 basis points and any performance-related basis-point adjustments, described in more detail below. Therefore, Ameren Illinois' annual ROE for its electric energy-efficiency investments is directly correlated to the yields on such bonds. Regulatory assets applicable to formula ratemaking for electric energy-efficiency investments earn a return at the applicable WACC. However, Ameren Illinois recognizes the carrying cost of debt on these regulatory assets in revenue, instead of the applicable WACC, with the difference recognized in revenues when recovery of such regulatory assets is reflected in customer rates.

Ameren Illinois' electric distribution service business is also subject to performance metrics. Failure to achieve the metrics would result in a reduction in the company's allowed ROE calculated under the MYRP. In 2022, the ICC issued an order approving total ROE incentives and penalties of 24 basis points under the MYRP, allocated among seven performance metrics. These performance metrics include improvements in service reliability in both the frequency and duration of outages, a reduction in peak loads, an increased percentage of spend with diverse suppliers, a reduction in disconnections for certain customers, and improved timeliness in response to customer requests for interconnection of distributed energy resources. These performance metrics apply annually from 2024 through 2027 under the MYRP, and the impact of any incentives and penalties will be excluded from the reconciliation cap described above. In addition, the allowed ROE on energy-efficiency investments can be increased or decreased up to 200 basis points, depending on the achievement of annual energy savings goals. Any adjustments to the allowed ROE for energy-efficiency investments will depend on annual performance for a historical period relative to energy savings goals. In 2024, 2023, and 2022, there were no performance-related basis-point adjustments that materially affected financial results.

Ameren Illinois' natural gas distribution business has recovery mechanisms, including the PGA and VBA, that allow customer rates to be adjusted without a traditional regulatory rate review. These riders, described in more detail below, mitigate the effects of regulatory lag. Ameren Illinois employs other riders for natural gas customer energy-efficiency program costs and certain environmental costs, as well as bad debt write-offs and invested capital taxes not recovered in base rates. Pass-through costs under the riders do not affect Ameren Illinois' net income, as any change in costs is offset by a corresponding change in revenues. Ameren Illinois' cost recovery under any of its recovery mechanisms is subject to ICC prudence reviews.

The PGA allows Ameren Illinois to recover costs of natural gas purchased on behalf of its customers without a traditional regulatory rate review, subject to ICC prudence reviews. These pass-through purchased gas costs do not affect Ameren Illinois' net income, as any change in costs is offset by a corresponding change in revenues. The difference between actual natural gas costs and costs billed to customers in a given period is deferred as a regulatory asset or liability. The deferred amount is either collected from, or refunded to, customers in a subsequent period. PGA regulatory assets earn carrying costs at short-term interest rates.

The VBA ensures recoverability of the natural gas distribution service revenue requirement that is dependent on sales volumes for residential and small nonresidential customers. For these rate classes, the VBA allows Ameren Illinois to adjust natural gas distribution service rates without a traditional regulatory rate review when changes occur in sales volumes from those volumes approved by the ICC in a previous regulatory rate review. The difference between allowed sales revenues and amounts billed to customers in a given period is deferred as a regulatory asset or liability. The deferred amount is either collected from, or refunded to, customers in a subsequent period. VBA regulatory assets for a given year that are not fully collected by the end of the following year begin earning carrying costs at short-term interest rates.

Federal

The FERC regulates rates and other matters for Ameren Illinois' transmission business and ATXI, as well as for Ameren Missouri. See the discussion above related to Ameren Missouri. Both Ameren Illinois and ATXI are members of the MISO, and their transmission rates are calculated in accordance with the MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff. Ameren Illinois and ATXI have received FERC approval to use a company-specific, forward-looking formula ratemaking framework in setting their transmission rates. These forward-looking rates are updated annually and become effective each January with forecasted information. The formula rate framework provides for an annual reconciliation of the electric transmission service revenue requirement, which reflects the actual recoverable costs incurred and the 13-month average rate base for a given year, with the revenue requirement in customer rates, including an allowed ROE. If a given year's revenue requirement varies from the amount collected from customers, an adjustment is made to electric operating revenues with an offset to a regulatory asset or liability to reflect that year's actual revenue requirement, independent of actual sales volumes. The regulatory balance is collected from, or refunded to, customers within two years from the end of the year. FERC revenue requirement reconciliation adjustment regulatory assets earn carrying costs at each company's short-term interest rates. In addition, the FERC has approved transmission rate incentives, including a 50-basis-point incentive adder to the allowed base ROE for Ameren Illinois and ATXI for participation in an RTO.

Missouri

2024 Electric Service Regulatory Rate Review

In June 2024, Ameren Missouri filed a request with the MoPSC seeking approval to increase its annual revenues for electric service. In February 2025, Ameren Missouri filed an updated electric rate increase request seeking approval to increase its annual revenues for electric service by \$446 million. The electric rate increase request is based on a 10.25% ROE, a capital structure composed of 52% common equity, a rate base of \$13.9 billion, and a test year ended March 31, 2024, with certain pro-forma adjustments through the true-up date of December 31, 2024. Ameren Missouri also requested the continued use of all of its existing riders and trackers. The electric rate increase request reflects the following:

- increased infrastructure investments made under Ameren Missouri's Smart Energy Plan, including increased cost of capital and depreciation expense. Included in these investments are 500 megawatts of solar generation investment for the Boomtown, Cass County and Huck Finn projects along with investments in the Callaway nuclear energy center and other dispatchable generation to support a reliable, low-cost and cleaner mix of energy resources;
- decreased costs resulting from the retirement of the Rush Island Energy Center; and
- decreased costs related to the extension of the retirement date of the Sioux Energy Center from 2030 to 2032 to ensure reliability.

In February 2025, the MoPSC staff recommended an increase to Ameren Missouri's annual electric service revenues of \$384 million based on a 9.74% ROE, a capital structure composed of 52% common equity, and a rate base of \$13.9 billion. The MoPSC staff's recommendation includes adjustments for lower off-system sales revenue, production tax credits, and renewable energy credits as a result of the curtailed nighttime operations at the High Prairie Energy Center to limit its impact on protected species. See Note 14 – Commitments and Contingencies for additional information on the curtailed nighttime operations at the High Prairie Energy Center. The MoPSC staff supported the continued use of all of Ameren Missouri's existing riders and trackers.

In December 2024, the MoOPC challenged 25% to 45% of the costs and requested return associated with the High Prairie Energy Center investment included in Ameren Missouri's requested revenue requirement as a result of the curtailed nighttime operations at the energy center discussed above.

The MoPSC proceeding relating to the proposed electric service rate changes will take place over a period of up to 11 months, with a decision by the MoPSC expected by May 2025 and new rates effective by June 2025. Ameren Missouri cannot predict the level of any electric service rate change the MoPSC may approve, whether the requested regulatory recovery mechanisms will be continued, or whether any rate change that may eventually be approved will be sufficient for Ameren Missouri to recover its costs and earn a reasonable return on its investments when the rate change goes into effect.

2024 Natural Gas Delivery Service Regulatory Rate Review

In September 2024, Ameren Missouri filed a request with the MoPSC seeking approval to increase its annual revenues for natural gas delivery service by \$40 million. The natural gas rate increase request is based on a 10.25% ROE, a capital structure composed of 52% common equity, a rate base of \$531 million, and a test year ended March 31, 2024, with certain pro-forma adjustments expected through the true-up date of December 31, 2024. The request includes the continued use of all of Ameren Missouri's existing riders and trackers. The natural gas rate increase request reflects investments in our existing natural gas infrastructure to ensure the safe delivery of natural gas.

The MoPSC proceeding relating to the proposed natural gas delivery service rate changes will take place over a period of up to 11 months, with a decision by the MoPSC expected by August 2025 and new rates effective by September 2025. Ameren Missouri cannot predict the level of any natural gas delivery service rate change the MoPSC may approve, whether the requested regulatory recovery mechanisms will be continued, or whether any rate change that may eventually be approved will be sufficient for Ameren Missouri to recover its costs and earn a reasonable return on its investments when the rate change goes into effect.

Generation Facilities

Ameren Missouri, and certain subsidiaries of Ameren Missouri, are parties to agreements to acquire and/or construct various generation facilities. The solar generation facilities are eligible for recovery under the PISA. The Castle Bluff Natural Gas Project is eligible for recovery under the post-construction cost deferral discussed below. The following table provides information with respect to each agreement:

	Agreement type	Facility size	Status of MoPSC CCN	Status of FERC approval of acquisition	In-service date ^(a)
Huck Finn Solar Project ^{(b)(c)}	Build-transfer	200-MW	Approved February 2023	Received March 2023	December 2024
Boomtown Solar Project ^{(b)(d)}	Build-transfer	150-MW	Approved April 2023	Received October 2023	December 2024
Cass County Solar Project ^{(b)(d)}	Development-transfer	150-MW	Approved June 2024	Not applicable	December 2024
Vandalia Solar Project ^{(b)(f)}	Self-build	50-MW	Approved March 2024	Not applicable	Fourth quarter 2025
Bowling Green Solar Project ^{(b)(f)}	Self-build	50-MW	Approved March 2024	Not applicable	First quarter 2026
Split Rail Solar Project ^{(b)(f)}	Build-transfer	300-MW	Approved March 2024	Received November 2024	Mid-2026
Castle Bluff Natural Gas Project ^(g)	Self-build	800-MW	Approved October 2024 ^(g)	Not applicable	Fourth quarter 2027

(a) In-service dates are dependent on the timing of construction completion, among other things. The assets of the Huck Finn, Boomtown, and Cass County solar projects were placed in service in December 2024.

(b) The Huck Finn Solar Project is expected to support Ameren Missouri's compliance with the state of Missouri's renewable energy standard. Investments in the project are eligible for recovery under the RESRAM.

(c) Ameren Missouri acquired the Cass County, Boomtown, and Huck Finn solar projects in June 2024, September 2024, and October 2024, respectively, and placed the assets of the projects, totaling \$1 billion, in service in December 2024.

(d) The Boomtown and Cass County solar projects are expected to support Ameren Missouri's transition to renewable energy generation and serve customers under the Renewable Solutions Program, which allows certain commercial, industrial, and governmental customers who enroll in the program to receive up to 100% of their energy from renewable resources.

(e) These projects collectively represent approximately \$1.7 billion of expected capital expenditures.

(f) These solar projects are expected to support Ameren Missouri's transition to renewable energy generation.

(g) For additional information see Castle Bluff Natural Gas Project CCN and Post-Construction Cost Deferral below.

Castle Bluff Natural Gas Project CCN and Post-Construction Cost Deferral

In October 2024, the MoPSC issued an order approving a nonunanimous stipulation and agreement filed by Ameren Missouri, the MoPSC staff, and other intervenors requesting a CCN for the Castle Bluff Natural Gas Project. The order also includes the use of a post-construction cost deferral related to the Castle Bluff Natural Gas Project, which allows Ameren Missouri to defer and recover depreciation expense, financing costs, and applicable income taxes incurred from the date the project is placed in service to the date when project costs are reflected in updated base rates as a result of a regulatory rate review. The period of deferral would be limited to the earlier of the time the project costs are reflected in base rates or six months.

Securitization of Rush Island Energy Center Costs

In June 2024, the MoPSC issued a financing order authorizing the issuance of securitized utility tariff bonds by AMF to finance \$476 million of costs related to the accelerated retirement of the Rush Island Energy Center, which included the remaining unrecovered net plant balance associated with the facility, among other costs. Ameren Missouri will collect the amounts necessary to repay the bonds over approximately 15 years from the date of bond issuance. The securitized tariff bonds were issued in December 2024. The financing order also included a determination that the decision to retire the Rush Island Energy Center was reasonable and prudent. The MoPSC did not make a determination regarding the prudence of Ameren Missouri's prior actions that resulted in the adverse ruling in the NSR and Clean Air Act litigation discussed in Note 14 – Commitments and Contingencies, however, claims regarding such actions could be considered in future regulatory proceedings. If future regulatory proceedings result in revenue reductions based on Ameren Missouri's prior actions that resulted in the adverse ruling in the NSR and Clean Air Act litigation, it could have a material adverse effect on the results of operations, financial position, and liquidity of Ameren and Ameren Missouri. Base rate revenues relating to the recovery of the Rush Island Energy Center are being deferred as a regulatory liability since the October 15, 2024 retirement date of the facility until new rates become effective related to the current electric service regulatory rate review. The amortization period for the regulatory liability will be determined in a future regulatory rate review. See Note 5 – Long-term Debt and Equity Financings for additional information on the securitized tariff bonds issuance.

MEEIA

In 2024, 2023, and 2022, Ameren Missouri achieved certain energy-efficiency spending goals for the MEEIA 2019 program. As a result of achieving these spending goals and MoPSC order issued in August 2022, Ameren Missouri recognized performance incentive revenues of \$13 million, \$12 million, and \$22 million, respectively.

In November 2024, the MoPSC issued an order approving a nonunanimous stipulation and agreement for Ameren Missouri's MEEIA 2025 plan, which includes a portfolio of customer energy-efficiency and demand response programs, along with the continued use of the MEEIA rider, which allows Ameren Missouri to collect from customers its actual MEEIA program costs, related lost electric revenues, and performance incentives. Ameren Missouri intends to invest \$51 million annually in 2025 and 2026 and \$22 million in 2027 for customer energy-efficiency and demand response programs.

In addition, the order approved performance incentives applicable to each plan year to earn revenues by achieving certain spending and demand response goals. If 100% of the goals are achieved in 2025, 2026, and 2027, Ameren Missouri would earn performance incentive revenues of \$5 million, \$5 million, and \$2 million, respectively.

MISO Long-Range Transmission Projects CCN

In 2022, the MISO approved the first tranche of projects related to a preliminary long-range transmission planning roadmap of projects through 2039. A portion of these projects were assigned or awarded via a competitive bid process to various utilities, including Ameren. In 2024, ATXI filed requests for CCNs, among other things, with the MoPSC related to the MISO long-range transmission projects that it expects to construct within the MoPSC's jurisdiction. Decisions by the MoPSC are expected in 2025.

Illinois

MYRP

In December 2023, the ICC issued an order in Ameren Illinois' MYRP proceeding approving base rates for electric distribution services for 2024 through 2027 and rejecting Ameren Illinois' Grid Plan, which was addressed as part of the MYRP proceeding. Rate changes consistent with the December 2023 order became effective in January 2024 and remained effective through late June 2024, when new rates became effective pursuant to the June 2024 ICC rehearing order discussed below. The December 2023 order adopted an alternative methodology to establish a rate base and revenue requirements for the years 2024 through 2027 using Ameren Illinois' previously approved 2022 year-end rate base. In January 2024, the ICC partially denied a rehearing requested by Ameren Illinois to revise the allowed ROE in the December 2023 order and granted Ameren Illinois' rehearing request to reconsider the rate base for each year of the MYRP and to include a base level of investments to maintain grid reliability in each year of the MYRP. In June 2024, the ICC issued an order on Ameren Illinois' rehearing request, which revised the rate bases for Ameren Illinois' MYRP test years to include investments for 2023 through 2027, among other things. New rates became effective in late June 2024 and remained effective through late December 2024, when new rates became effective pursuant to the December 2024 ICC order discussed below. For additional information on the ICC's June 2024 rehearing order, see the table below. In July 2024, Ameren Illinois filed a request for rehearing of the ICC's June 2024 rehearing order to include an asset associated with other postretirement benefits in the rate base. Subsequently, in August 2024, the ICC denied the rehearing request. Also, in January 2024, Ameren Illinois filed an appeal of the December 2023 ICC order, including the 8.72% ROE, and subsequently updated the appeal filing in September 2024 to include the June 2024 rehearing order regarding the inclusion of an asset associated with other postretirement benefits in the rate base to the Illinois Appellate Court for the Fifth Judicial District. The court is under no deadline to address the appeal and Ameren Illinois cannot predict the ultimate outcome of the appeal.

In March 2024, pursuant to the December 2023 ICC order discussed above, Ameren Illinois filed a revised Grid Plan and a revised MYRP to update the requested revenue requirements for 2024 through 2027. In December 2024, the ICC issued an order in connection with Ameren Illinois' revised Grid Plan and revised MYRP for electric distribution service for 2024 through 2027. Using the 2023 revenue requirement as a starting point, the approved revenue requirements in the ICC's December 2024 order represent a cumulative four-year increase of \$309 million. Rate changes consistent with the December 2024 order became effective in December 2024. In January 2025, Ameren Illinois filed a request for rehearing of the ICC's December 2024 order to revise the allowed ROE and to include an asset associated with other postretirement benefits in the rate base, among other things. Subsequently, in February 2025, the ICC denied the rehearing request. Ameren Illinois intends to file an appeal of the ICC's December 2024 order and update the appeal filed in September 2024 to the Illinois Appellate Court for the Fifth Judicial District as discussed above.

The following table presents the approved revenue requirements and average annual rate base in the ICC's December 2024 MYRP order and the ICC's June 2024 rehearing order:

Year	Revenue Requirement (in millions)	Average Annual Rate Base (in billions)
ICC's December 2024 MYRP Order^(a):		
2024	\$1,206	\$4.2
2025	\$1,287	\$4.4
2026	\$1,367	\$4.6
2027	\$1,422	\$4.8
ICC's June 2024 Rehearing Order^(a):		
2024	\$1,196	\$4.0
2025	\$1,282	\$4.3
2026	\$1,350	\$4.5
2027	\$1,397	\$4.7

(a) Based on an allowed ROE of 8.72% and a capital structure composed of 50% common equity. The ROE is under appeal, as discussed above. New rates became effective in December 2024.

2023 Electric Distribution Revenue Requirement Reconciliation Adjustment Order

In December 2024, the ICC issued an order approving Ameren Illinois' 2023 electric distribution service revenue requirement reconciliation adjustment filing. This order approved a reconciliation adjustment of \$158 million, which reflected Ameren Illinois' actual 2023 recoverable costs, year-end rate base of \$4.2 billion, and capital structure composed of 50% common equity. The approved reconciliation adjustment will be collected from customers in 2025.

Electric Customer Energy-Efficiency Investments

In November 2024, the ICC issued an order in Ameren Illinois' annual update filing that approved electric customer energy-efficiency rates of \$126 million beginning in January 2025, which represents an increase of \$26 million from 2024 rates. This order was based on a projected 2025 year-end rate base of \$434 million.

2025 Natural Gas Delivery Service Rate Review

In January 2025, Ameren Illinois filed a request with the ICC seeking approval to increase its annual revenues for natural gas delivery service by \$140 million. The request is based on a 10.7% ROE, a capital structure composed of 52% common equity, and a rate base of \$3.3 billion. Ameren Illinois used a 2026 future test year in this proceeding. A decision by the ICC in this proceeding is required by early December 2025, with new rates expected to be effective in December 2025. Ameren Illinois cannot predict the level of any delivery service rate change the ICC may approve, nor whether any rate change that may eventually be approved will be sufficient to enable Ameren Illinois to recover its costs and to earn a reasonable return on investments when the rate changes go into effect.

2023 Natural Gas Delivery Service Rate Order

In November 2023, the ICC issued an order in Ameren Illinois' January 2023 natural gas delivery service regulatory rate review, which resulted in an increase to its annual revenues for natural gas delivery service of \$112 million based on a 9.44% allowed ROE, a capital structure composed of 50% common equity, and a rate base of approximately \$2.85 billion. The order reflected a reduction of approximately \$93 million of planned distribution and transmission capital investments included in Ameren Illinois' requested revenue increase, which used a 2024 future test year. The new rates became effective on November 28, 2023.

In December 2023, Ameren Illinois filed a request for rehearing of the ICC's November 2023 order. The filing requested the ICC revise the order to include an allowed ROE of at least 9.89%, a capital structure composed of 52% common equity, and a reversal of the approximately \$93 million reduction of planned distribution and transmission capital investments included in the order, among other things. In January 2024, the ICC denied Ameren Illinois' rehearing request, and Ameren Illinois filed an appeal with the Illinois Appellate Court for the Fifth Judicial District. In January 2025, the appellate court ruled on the appeal filed by Ameren Illinois. In that ruling, the court reversed a reduction of planned transmission capital investments of \$48 million, but affirmed the ICC-approved 9.44% ROE and the remaining reduction of planned distribution capital investments.

Future of Gas Proceeding

The ICC's November 2023 natural gas delivery service rate order discussed above directed the ICC staff to develop a plan for a future of gas proceeding. All of the Illinois natural gas utilities subject to ICC regulation are included in this proceeding, which is exploring issues involving the decarbonization of the natural gas distribution system in light of the state of Illinois' goal of economy-wide 100% clean energy by 2050, pursuant to the CEJA. Some of the issues being addressed include the mitigation of any natural gas distribution stranded assets, the role of energy efficiency in decarbonization, and the associated impacts of natural gas decarbonization to the electric distribution system, among others. A final ICC staff report is expected in early 2026 and will be used by the ICC to guide further action, if any.

QIP Reconciliation Hearing

In 2021, Ameren Illinois filed a request with the ICC to initiate a reconciliation proceeding of natural gas capital investments recovered under the QIP rider during 2020. In September 2024, the Illinois Attorney General's office challenged the recovery of capital investments that were made during 2020, alleging that the ICC should disallow approximately \$30 million in natural gas capital investments as improper and imprudent, resulting in a potential over-recovery of an immaterial amount by Ameren Illinois in 2020. In October 2023, and again in September 2024, the ICC staff filed testimony that supports the prudence and reasonableness of the capital investments made during 2020. Ameren Illinois' 2020 QIP rate recovery request under review by the ICC was within the rate increase limitations allowed by law. The ICC is under no deadline to issue an order in this proceeding. In addition, 2021 through 2023 reconciliation proceedings are still ongoing. Ameren Illinois cannot predict the ultimate outcome of these regulatory proceedings.

MISO Long-Range Transmission Projects CCN

In 2022, the MISO approved the first tranche of projects related to a preliminary long-range transmission planning roadmap of projects through 2039. A portion of these projects were assigned or awarded via a competitive bidding process to various utilities, including Ameren. In February 2024, Ameren Illinois and ATXI filed a request for a CCN, among other things, with the ICC related to the portion of the MISO long-range transmission projects they will construct within the ICC's jurisdiction. A decision by the ICC is expected by mid-2025.

Federal

FERC ROE Complaint Cases

Since November 2013, the allowed base ROE for FERC-regulated transmission rate base under the MISO tariff has been subject to customer complaint cases and has been changed by various FERC orders. In May 2020, the FERC issued an order, which set the allowed base ROE to 10.02% and required refunds, with interest, for the periods from November 2013 to February 2015 and from late September 2016 forward. Ameren and Ameren Illinois paid these refunds, including interest, by March 31, 2022. In 2020, Ameren Missouri, Ameren Illinois, and ATXI, as well as various customers, petitioned the United States Court of Appeals for the District of Columbia Circuit for review of the May 2020 order, challenging certain aspects of the new ROE methodology established. The petition filed by Ameren Missouri, Ameren Illinois, and ATXI challenged the refunds required for the period from September 2016 to May 2020. In August 2022, the court issued a ruling that granted the customers' petition for review, vacated the FERC's previous MISO ROE-determining orders, and remanded the proceedings to the FERC. The court elected not to rule on the issues raised by Ameren Missouri, Ameren Illinois, and ATXI. In October 2024, the FERC issued an order, which decreased the allowed base ROE from 10.02% to 9.98% and required refunds, with interest, for the same periods covered by the May 2020 order. In November 2024, the MISO transmission owners, including Ameren Missouri, Ameren Illinois, and ATXI, filed a request for rehearing with the FERC, arguing, among other things, the FERC should not have ordered refunds back to September 2016 or imposed interest on those refunds. Also in November 2024, another intervenor filed a request for rehearing with the FERC, requesting the FERC correct aspects of the ROE methodology used in the October 2024 order and reconsider its decision in a February 2015 complaint case to deny refunds for the period from February 2015 to May 2016. In December 2024, the FERC issued a notice indicating a future order related to the rehearing requests will be issued but did not specify a timeline. In January 2025, the MISO transmission owners, including Ameren Missouri, Ameren Illinois, and ATXI, filed an appeal of the October 2024 order to the United States Court of Appeals for the District of Columbia Circuit.

As a result of the October 2024 order, Ameren and Ameren Illinois recognized reductions to "Operating Revenues – Electric" on their statements of income of \$10 million and \$7 million, respectively, and recognized expense of \$2 million and \$1 million, respectively, in "Interest charges" on their statements of income in 2024. As of December 31, 2024, Ameren and Ameren Illinois had recorded liabilities in "Current regulatory liabilities" on their balance sheets of \$12 million and \$8 million, respectively, to reflect the expected refunds, including interest, associated with the allowed base ROE set by the October 2024 order.

Regulatory Assets and Liabilities

The following table presents our regulatory assets and regulatory liabilities in accordance with GAAP authoritative guidance at December 31, 2024 and 2023:

	2024			2023		
	Ameren Missouri	Ameren Illinois	Ameren	Ameren Missouri	Ameren Illinois	Ameren
Regulatory assets:						
Under-recovered FAC ^(a)	\$ 41	\$ —	\$ 41	\$ 72	\$ —	\$ 72
MTM derivative losses ^(b)	15	88	103	25	143	168
IEIMA revenue requirement reconciliation adjustment ^{(c)(d)}	—	139	139	—	239	239
MYRP revenue requirement reconciliation adjustment ^{(e)(f)}	—	24	24	—	—	—
Under-recovered RBA ^(g)	—	22	22	—	—	—
FERC revenue requirement reconciliation adjustment ^(g)	—	55	90	—	25	54
Under-recovered VBA ^(h)	—	49	49	—	49	49
Income taxes ⁽ⁱ⁾	237	81	322	126	78	207
Bad debt rider ^(j)	—	25	25	—	43	43
Callaway refueling and maintenance outage costs ^(k)	13	—	13	37	—	37
Unamortized loss on reacquired debt ^(l)	42	5	47	45	5	50
Environmental cost riders ^(m)	—	43	43	—	50	50
Storm costs ^{(d)(n)}	—	18	18	—	27	27
Customer generation rebate program ^{(d)(o)}	—	89	89	—	54	54
PISA ^{(d)(p)}	464	—	464	386	—	386
Rush Island Energy Center securitization ^(q)	465	—	465	—	—	—
RESRAM ^(r)	51	—	51	48	—	48
Certain Meramec Energy Center costs ^(s)	26	—	26	39	—	39
Energy-efficiency rider ^{(d)(t)}	—	576	576	—	500	500
Property tax tracker ^(u)	22	—	22	13	—	13
Other	56	78	134	65	74	139
Total regulatory assets	\$ 1,432	\$ 1,292	\$ 2,763	\$ 856	\$ 1,287	\$ 2,175
Less: current regulatory assets	(66)	(281)	(366)	(101)	(252)	(365)
Noncurrent regulatory assets	\$ 1,366	\$ 1,011	\$ 2,397	\$ 755	\$ 1,035	\$ 1,810
Regulatory liabilities:						
Over-recovered Illinois electric power costs ^(v)	—	34	34	—	36	36
Over-recovered PGA ^(v)	2	33	35	7	33	40
MTM derivative gains ^(b)	10	6	16	19	3	22
Income taxes ⁽ⁱ⁾	1,040	679	1,804	999	724	1,809
Cost of removal ^(w)	1,118	1,115	2,294	1,098	1,038	2,186
AROs ^(d)	691	—	691	524	—	524
Pension and postretirement benefit costs ^(x)	202	156	358	202	144	346
Pension and postretirement benefit costs tracker ^(z)	70	—	70	111	—	111
Renewable energy credits and zero emission credits ^(aa)	—	586	586	—	489	489
Certain Rush Island Energy Center costs ^(aa)	66	—	66	—	—	—
Other	14	43	63	14	22	36
Total regulatory liabilities	\$ 3,213	\$ 2,652	\$ 6,017	\$ 2,974	\$ 2,489	\$ 5,599
Less: current regulatory liabilities	(37)	(79)	(120)	(15)	(71)	(87)
Noncurrent regulatory liabilities	\$ 3,176	\$ 2,573	\$ 5,897	\$ 2,959	\$ 2,418	\$ 5,512

- (a) Under-recovered fuel and purchased power costs to be recovered through the FAC. Specific accumulation periods aggregate the under-recovered costs over four months, any related adjustments that occur over the following four months, and the recovery from customers that occurs over the next eight months.
- (b) Deferral of commodity-related derivative MTM losses or gains. See Note 7 – Derivative Financial Instruments for additional information.
- (c) The difference between Ameren Illinois' electric distribution service annual revenue requirement calculated under the IEIMA performance-based formula ratemaking framework and the revenue requirement included in customer rates for that year. The under-recovery will be recovered from customers with a return at the applicable WACC within two years.
- (d) These assets earn a return at the applicable WACC.

- (e) The difference between Ameren Illinois' actual electric distribution revenue requirement, as adjusted for certain cost variations, and the ICC-approved revenue requirement, subject to a reconciliation cap. The under-recovery will be recovered from customers with a return at the applicable WACC within two years.
- (f) Under-recovered electric distribution service revenue caused by sales volume and/or wholesale and miscellaneous revenue deviations from the related revenue requirement approved by the ICC for a given year. The under-recovery will be recovered from customers within two years.
- (g) Ameren Illinois' and ATXI's annual revenue requirement reconciliation calculated pursuant to the FERC's electric transmission formula ratemaking framework. Any under-recovery or over-recovery will be recovered from, or refunded to, customers within two years.
- (h) Under-recovered natural gas revenue caused by sales volume deviations from weather normalized sales approved by the ICC in rate regulatory reviews. Each year's amount will be recovered from customers from April through December of the following year.
- (i) The regulatory assets represent amounts that will be recovered from customers for deferred income taxes related to the equity component of allowance for funds used during construction, the securitization of the Rush Island Energy Center, and the effects of tax rate increases. The regulatory liabilities represent amounts that will be refunded to customers for excess deferred income taxes related to depreciation differences caused by a decrease in the statutory rates, other tax liabilities, and amounts related to the unamortized portion of investment tax credits. Amounts associated with the equity component of allowance for funds used during construction, the securitization of the Rush Island Energy Center, and amounts related to the unamortized portion of investment tax credits will be amortized over the expected life of the related assets. For net regulatory liabilities related to deferred income taxes recorded at rates other than the current statutory rate, the weighted-average remaining amortization periods at Ameren, Ameren Missouri, and Ameren Illinois are 39, 30, and 46 years. In addition, the regulatory liabilities for Ameren Missouri include a regulatory recovery mechanism for the difference between production and investment tax credits or proceeds from the sale of such tax credits allowed under the IRA and the level of such tax credits included in customer rates. The period of refund varies based on MoPSC approval in a regulatory rate review. The amortization period will be determined in a future regulatory rate review.
- (j) A rider for the difference between the level of bad debt write-offs, net of any subsequent recoveries, incurred by Ameren Illinois and the level of such costs included in electric distribution and natural gas delivery service rates. Under-recovered or over-recovered costs for each year are collected from, or refunded to, customers over a twelve-month period beginning in June of the following year.
- (k) Maintenance expenses related to scheduled refueling and maintenance outages at Ameren Missouri's Callaway Energy Center. Amounts are amortized over the period between refueling and maintenance outages, which has historically been approximately 18 months.
- (l) Losses related to reacquired debt. These amounts are being amortized over the lives of the related new debt issuances or the original lives of the old debt issuances if no new debt was issued.
- (m) The recoverable portion of accrued environmental site liabilities that will be collected from electric and natural gas customers through ICC-approved cost recovery riders. The period of recovery will depend on the timing of remediation expenditures. See Note 14 – Commitments and Contingencies for additional information.
- (n) Storm costs from 2020 through 2023 deferred in accordance with the IEIMA and MYRP. These costs are being amortized over five-year periods beginning in the year the storm occurred.
- (o) Costs associated with Ameren Illinois' customer generation rebate program. Costs are amortized over a 15-year period, beginning in the year rebates are paid.
- (p) Under the PISA, Ameren Missouri is permitted to defer and recover 85% of the depreciation expense and earn a return at the applicable WACC on 85% of investments in certain property, plant, and equipment placed in service and not included in base rates. Accumulated PISA deferrals, which also earn a return at the applicable WACC, are added to rate base prospectively and amortized over a period of 20 years following a regulatory rate review.
- (q) In June 2024, the MoPSC issued a financing order authorizing the issuance of securitized utility tariff bonds by AMF to finance costs related to the accelerated retirement of the Rush Island Energy Center, which includes the remaining unrecovered net plant balance associated with the facility, among other costs. Ameren Missouri will collect the amounts necessary to repay the securitized utility tariff bonds over approximately 15 years beginning in December 2024.
- (r) Under-recovered costs associated with Ameren Missouri's compliance with the state of Missouri's renewable energy standard. Under-recovered or over-recovered costs are aggregated over a twelve-month period beginning each August and are amortized over a twelve-month period beginning in February of the following year.
- (s) Certain costs associated with the Meramec Energy Center, which were authorized for recovery by a December 2021 MoPSC electric rate order. These costs are being collected over five years beginning in February 2022.
- (t) The electric energy-efficiency investments are being amortized over their weighted-average useful lives beginning in the period in which they were made, with current remaining amortization periods ranging from two to 12 years.
- (u) A regulatory recovery mechanism for the difference between actual property taxes incurred by Ameren Missouri and the related taxes included in customer rates. The period of recovery, or refund, varies based on MoPSC approval in a regulatory rate review. Amounts accumulated through 2022 are being collected over two years beginning July 2023. The amortization period for amounts accumulated after 2022 will be determined in a future regulatory rate review.
- (v) Over-recovered costs from utility customers. Amounts will be refunded to customers within one year of the deferral.
- (w) Estimated funds collected from customers to pay for the future removal cost of property, plant, and equipment when retired from service, net of salvage.
- (x) The ARO regulatory liability includes the nuclear decommissioning trust fund balance (\$1,342 million and \$1,150 million at December 31, 2024 and 2023, respectively), net of recoverable removal costs for AROs (\$651 million and \$626 million at December 31, 2024 and 2023, respectively). See Note 1 – Summary of Significant Accounting Policies – Asset Retirement Obligations and Removal Costs.
- (y) Over-recovered costs are being amortized in proportion to the recognition of prior service costs (credits) and actuarial losses (gains) attributable to Ameren's pension plan and postretirement benefit plans. See Note 10 – Retirement Benefits for additional information.
- (z) A regulatory recovery mechanism for the difference between the level of pension and postretirement benefit costs incurred by Ameren Missouri and the level of such costs included in customer rates. The period of refund varies based on MoPSC approval in a regulatory rate review. For electric and natural gas related costs incurred prior to 2023 and 2022, respectively, the weighted-average remaining amortization period is two years. For electric and natural gas related costs incurred after 2023 and 2022, respectively, the amortization period will be determined in a future regulatory rate review.
- (aa) Funds collected for the purchase of renewable energy credits and zero emission credits through IPA procurements. The balance will be amortized as the credits are purchased. Pursuant to the CEJA, if funds collected from customers are not used to procure renewable energy credits, they would be refunded to customers pursuant to an annual reconciliation proceeding, the latest of which was approved by the ICC in January 2025 and did not result in refunds to customers.
- (ab) Funds collected from the issuance of securitized utility tariff bonds by AMF primarily to pay for the decommissioning of the Rush Island Energy Center. The amortization period for the difference between the estimated costs and the actual costs incurred will be determined in a future regulatory rate review.

NOTE 3 – PROPERTY, PLANT, AND EQUIPMENT, NET

The following table presents components of GAAP "Property, plant, and equipment, net" at December 31, 2024 and 2023:

	Ameren Missouri	Ameren Illinois	Other	Ameren
2024				
Property, plant, and equipment at original cost ^(a) :				
Electric generation:				
Coal ^(b)	\$ 3,556	\$ —	\$ —	\$ 3,556
Natural gas	938	—	—	938
Nuclear	5,931	—	—	5,931
Renewable ^(c)	2,901	19	—	2,920
Electric distribution	9,469	8,160	—	17,629
Electric transmission	2,406	5,725	2,031	10,162
Natural gas	776	4,421	—	5,197
Other ^(d)	2,427	1,770	260	4,457
	28,404	20,095	2,291	50,790
Less: Accumulated depreciation and amortization	10,875	5,184	436	16,495
	17,529	14,911	1,855	34,295
Construction work in progress:				
Nuclear fuel in progress	268	—	—	268
Other	991	619	131	1,741
Property, plant, and equipment, net	\$ 18,788	\$ 15,530	\$ 1,986	\$ 36,304
2023				
Property, plant, and equipment at original cost ^(a) :				
Electric generation:				
Coal ^(b)	\$ 3,452	\$ —	\$ —	\$ 3,452
Natural gas	921	—	—	921
Nuclear	5,879	—	—	5,879
Renewable ^(c)	1,973	11	—	1,984
Electric distribution	8,638	7,820	—	16,458
Electric transmission	2,134	5,381	1,993	9,508
Natural gas	688	4,186	—	4,874
Other ^(d)	2,191	1,657	255	4,103
	25,876	19,055	2,248	47,179
Less: Accumulated depreciation and amortization ^(f)	10,243	4,783	400	15,426
	15,633	14,272	1,848	31,753
Construction work in progress:				
Nuclear fuel in progress	173	—	—	173
Other	914	360	46	1,320
Plant to be abandoned, net ^(e)	530	—	—	530
Property, plant, and equipment, net	\$ 17,250	\$ 14,632	\$ 1,894	\$ 33,776

- (a) The estimated lives for each asset group are as follows: 5 to 72 years for electric generation, excluding Ameren Missouri's hydroelectric generating assets, which have useful lives of up to 150 years; 20 to 80 years for electric distribution; 50 to 75 years for electric transmission; 20 to 80 years for natural gas; and 2 to 55 years for other.
- (b) Includes \$30 million and \$29 million of oil-fired generation at December 31, 2024 and 2023, respectively.
- (c) Renewable includes hydroelectric, wind, solar, and methane gas generation facilities.
- (d) Other property, plant, and equipment includes assets used to support electric and natural gas services.
- (e) Represents the net book value of the Rush Island Energy Center as Ameren Missouri retired the energy center in October 2024, significantly in advance of its previously expected useful life. See Plant to be Abandoned, Net under Note 1 – Summary of Significant Accounting Policies, NSR and Clean Air Act Litigation under Note 14 – Commitments and Contingencies, and Securitization of Rush Island Energy Center Costs under Note 2 – Rate and Regulatory Matters for additional information on the accelerated retirement of the Rush Island Energy Center.

Capitalized software costs are classified within "Property, Plant, and Equipment, Net" on the balance sheet and are amortized on a straight-line basis over the expected period of benefit, ranging from 2 to 15 years, with the amortization expense included in "Depreciation and amortization" on the statement of income. Deferred cloud implementation costs are classified within "Other Assets" on the balance sheet and are amortized on a straight-line basis over the term of the associated hosting arrangement, ranging from 5 to 15 years, with the amortization expense included in "Other operations

and maintenance" on the statement of income. The following table presents the amortization expense, gross carrying value, and related accumulated amortization of capitalized software and deferred cloud implementation costs by year:

	Amortization Expense			Gross Carrying Value		Accumulated Amortization	
	2024	2023	2022	2024	2023	2024	2023
Capitalized software costs:							
Ameren	\$ 224	\$ 212	\$ 159	\$ 1,996	\$ 1,823	\$ (1,348)	\$ (1,126)
Ameren Missouri	118	114	85	881	795	(567)	(453)
Ameren Illinois	100	92	69	867	786	(552)	(452)
Deferred cloud implementation costs:							
Ameren	\$ 20	\$ 17	\$ 15	\$ 157	\$ 142	\$ (71)	\$ (51)
Ameren Missouri	9	8	7	71	63	(32)	(23)
Ameren Illinois	10	9	8	82	76	(36)	(26)

Annual amortization expense for capitalized software placed in service as of December 31, 2024, is estimated to be as follows:

	2025	2026	2027	2028	2029
Ameren	\$ 190	\$ 147	\$ 110	\$ 69	\$ 38
Ameren Missouri	98	73	54	33	17
Ameren Illinois	85	70	53	34	20

NOTE 4 – SHORT-TERM DEBT AND LIQUIDITY

The liquidity needs of the Ameren Companies are supported through the use of available cash, drawings under committed credit agreements, commercial paper issuances, and/or, in the case of Ameren Missouri and Ameren Illinois, short-term affiliate borrowings.

Short-Term Borrowings

In December 2024, the Credit Agreements, which were scheduled to mature in December 2027, were extended and now mature in December 2028. The Credit Agreements provide \$2.6 billion of credit cumulatively through maturity in December 2028. The total facility size of the Missouri Credit Agreement and Illinois Credit Agreement is \$1.4 billion and \$1.2 billion, respectively. The maturity date of each Credit Agreement may be extended for an additional one-year period upon the mutual consent of the respective borrowers and the lenders. Credit available under the agreements is provided by 20 international, national, and regional lenders, with no single lender providing more than \$156 million of credit in aggregate.

The obligations of each borrower under the respective Credit Agreements to which it is a party are several and not joint. Except under limited circumstances relating to expenses and indemnities, the obligations of Ameren Missouri and Ameren Illinois under the respective Credit Agreements are not guaranteed by Ameren (parent) or any other subsidiary of Ameren. The following table presents the maximum aggregate amount available to each borrower under each facility:

	Missouri Credit Agreement	Illinois Credit Agreement
Ameren (parent)	\$ 1,000	\$ 700
Ameren Missouri	1,000	(a)
Ameren Illinois	(a)	1,000

(a) Not applicable.

The borrowers have the option to seek additional commitments from existing or new lenders to increase the total facility size of the Credit Agreements to a maximum of \$1.7 billion for the Missouri Credit Agreement and \$1.5 billion for the Illinois Credit Agreement. Ameren (parent) borrowings are due and payable no later than the maturity date of the Credit Agreements. Ameren Missouri and Ameren Illinois borrowings under the applicable Credit Agreement are due and payable no later than the earlier of the maturity date or 364 days after the date of the borrowing.

The obligations of the borrowers under the Credit Agreements are unsecured. Loans are available on a revolving basis under each of the Credit Agreements. Funds borrowed may be repaid and, subject to satisfaction of the conditions to borrowing, reborrowed from time to time. At the election of each borrower, the interest rates on such loans will be the alternate base rate plus the margin applicable to the particular borrower and/or the eurodollar rate plus the margin applicable to the particular borrower. The applicable margins will be determined by the borrower's long-term unsecured credit ratings or, if no such ratings are in effect, the borrower's corporate/issuer ratings then in effect. The borrowers have received commitments from the lenders to issue letters of credit up to \$100 million under each of the Credit Agreements. In addition, the issuance of letters of credit is subject to the \$2.6 billion overall combined facility borrowing limitations of the Credit Agreements.

The borrowers will use the proceeds from any borrowings under the Credit Agreements for general corporate purposes, including working capital, loan funding under the Ameren money pool arrangements, and other short-term affiliate loan arrangements. The Missouri Credit Agreement and the Illinois Credit Agreement are available to support issuances under Ameren (parent)'s, Ameren Missouri's and Ameren Illinois' commercial paper programs, respectively, subject to borrowing sublimits, as well as to support issuance of letters of credit for the borrowers. As of December 31, 2024, based on credit capacity available under the Credit Agreements, along with cash and cash equivalents, the net liquidity available to Ameren (parent), Ameren Missouri, and Ameren Illinois, collectively, was \$1.4 billion.

The following table summarizes the activity and relevant interest rates for Ameren (parent)'s, Ameren Missouri's, and Ameren Illinois' commercial paper issuances under the Credit Agreements in the aggregate for the years ended December 31, 2024 and 2023:

	Ameren (parent)	Ameren Missouri	Ameren Illinois	Ameren Consolidated
2024				
Average daily amount outstanding	\$ 377	\$ 192	\$ 193	\$ 762
Commercial paper issuances outstanding at period-end	1,055	—	88	1,143
Weighted-average interest rate	5.10 %	5.34 %	5.57 %	5.28 %
Peak amount outstanding during period ^(a)	\$ 1,091	\$ 595	\$ 694	\$ 1,569
Peak interest rate	5.60 %	5.68 %	5.68 %	5.68 %
2023				
Average daily amount outstanding	\$ 726	\$ 274	\$ 166	\$ 1,166
Commercial paper issuances outstanding at period-end	—	170	366	536
Weighted-average interest rate	5.38 %	5.22 %	5.23 %	5.32 %
Peak amount outstanding during period ^(a)	\$ 1,298	\$ 592	\$ 450	\$ 1,526
Peak interest rate	5.65 %	5.68 %	5.68 %	5.68 %

(a) The timing of peak outstanding commercial paper issuances and borrowings under the Credit Agreements varies by company. Therefore, the sum of individual company peak amounts may not equal the Ameren consolidated peak amount for the period.

Indebtedness Provisions and Other Covenants

The information below is a summary of the Ameren Companies' compliance with indebtedness provisions and other covenants.

The Credit Agreements contain conditions for borrowings and issuances of letters of credit. These conditions include the absence of default or unmatured default, material accuracy of representations and warranties (excluding any representation after the closing date as to the absence of material adverse change and material litigation, and the absence of any notice of violation, liability, or requirement under any environmental laws that could have a material adverse effect), and obtaining required regulatory authorizations. In addition, it is a condition for any Ameren Illinois borrowing that, at the time of and after giving effect to such borrowing, Ameren Illinois not be in violation of any limitation on its ability to incur unsecured indebtedness contained in its articles of incorporation.

The Credit Agreements also contain nonfinancial covenants, including restrictions on the ability to incur certain liens, to transact with affiliates, to dispose of assets, to make investments in or transfer assets to its affiliates, and to merge with other entities. The Credit Agreements require each of Ameren, Ameren Missouri, and Ameren Illinois to maintain consolidated indebtedness of not more than 65% of its consolidated total capitalization pursuant to a defined calculation set forth in the agreements. As of December 31, 2024, the ratios of consolidated indebtedness to total consolidated capitalization, calculated in accordance with the provisions of the Credit Agreements, were 60%, 48%, and 45%, for Ameren, Ameren Missouri, and Ameren Illinois, respectively.

The Credit Agreements contain default provisions that apply separately to each borrower. However, a default of Ameren Missouri or Ameren Illinois under the applicable credit agreement is also deemed to constitute a default of Ameren (parent) under such agreement. Defaults include a cross-default resulting from a default of such borrower under any other agreement covering outstanding indebtedness of such borrower and certain subsidiaries (other than project finance subsidiaries, nonmaterial subsidiaries, and certain special purposes entities contemplated in the Credit Agreements) in excess of \$100 million in the aggregate (including under the other credit agreement). However, under the default provisions of the Credit Agreements, any default of Ameren (parent) under either credit agreement that results solely from a default of Ameren Missouri or Ameren Illinois does not result in a cross-default of Ameren (parent) under the other credit agreement. Further, the Credit Agreements default provisions provide that an Ameren (parent) default under either of the Credit Agreements does not constitute a default by Ameren Missouri or Ameren Illinois.

None of the Credit Agreements or financing agreements contain credit rating triggers that would cause a default or acceleration of repayment of outstanding balances. The Ameren Companies were in compliance with the provisions and covenants of the Credit Agreements at December 31, 2024.

Money Pools

Ameren (parent) has money pool agreements with and among its subsidiaries to coordinate and provide for certain short-term cash and working capital requirements.

Ameren Missouri, Ameren Illinois, and ATXI may participate in the utility money pool as both lenders and borrowers. Ameren (parent) and Ameren Services may participate in the utility money pool only as lenders. Surplus internal funds are contributed to the money pool from participants. The primary sources of external funds for the utility money pool are the Credit Agreements and the commercial paper programs. The total amount available to the pool participants from the utility money pool at any given time is reduced by the amount of borrowings made by participants, but it is increased to the extent that the pool participants advance surplus funds to the utility money pool or remit funds from other external sources. The availability of funds is also determined by funding requirement limits established by regulatory authorizations. Participants receiving a loan under the utility money pool agreement must repay the principal amount of such loan, together with accrued interest. The rate of interest depends on the composition of internal and external funds in the utility money pool. The average interest rate for borrowing under the utility money pool for the year ended December 31, 2024, was 5.19% (2023 – 5.29%).

See Note 13 – Related-party Transactions for the amount of interest income and expense from the utility money pool agreement recorded by Ameren Missouri and Ameren Illinois for the years ended December 31, 2024, 2023, and 2022.

NOTE 5 – LONG-TERM DEBT AND EQUITY FINANCINGS

The following table presents long-term debt outstanding, including maturities due within one year, as of December 31, 2024 and 2023:

	2024	2023
Ameren (Parent):		
2.50% Senior unsecured notes due 2024	\$ —	\$ 450
3.65% Senior unsecured notes due 2026	350	350
5.70% Senior unsecured notes due 2026	600	600
1.95% Senior unsecured notes due 2027	500	500
1.75% Senior unsecured notes due 2028	450	450
5.00% Senior unsecured notes due 2029	700	700
3.50% Senior unsecured notes due 2031	800	800
Total long-term debt, gross	3,400	3,850
Less: Unamortized discount and premium	(3)	(4)
Less: Unamortized debt issuance costs	(14)	(17)
Less: Maturities due within one year	—	(450)
Long-term debt, net	\$ 3,383	\$ 3,379
Ameren Missouri:		
Bonds and notes:		
3.50% Senior secured notes due 2024 ^(a)	\$ —	\$ 350
2.95% Senior secured notes due 2027 ^(a)	400	400
3.50% First mortgage bonds due 2029 ^(a)	450	450
2.95% First mortgage bonds due 2030 ^(a)	465	465
2.15% First mortgage bonds due 2032 ^(a)	525	525
2.90% 1998 Series A bonds due 2033 ^(a)	60	60
2.90% 1998 Series B bonds due 2033 ^(a)	50	50
2.75% 1998 Series C bonds due 2033 ^(a)	50	50
5.20% First mortgage bonds due 2034 ^(a)	500	—
5.50% Senior secured notes due 2034 ^(a)	184	184
5.30% Senior secured notes due 2037 ^(a)	300	300
8.45% Senior secured notes due 2039 ^{(a)(d)}	350	350
4.85% Securitized utility tariff bonds due 2039 ^(a)	476	—
3.90% Senior secured notes due 2042 ^{(a)(d)}	485	485
3.65% Senior secured notes due 2045 ^(a)	400	400
4.00% First mortgage bonds due 2048 ^(a)	425	425
3.25% First mortgage bonds due 2049 ^(a)	330	330
2.625% First mortgage bonds due 2051 ^(a)	550	550
3.90% First mortgage bonds due 2052 ^(a)	525	525
5.45% First mortgage bonds due 2053 ^(a)	500	500
5.25% First mortgage bonds due 2054 ^(a)	350	—
5.125% First mortgage bonds due 2055 ^(a)	450	—
Total long-term debt, gross	7,825	6,399
Less: Long-term debt – related parties, gross	(58)	—
Less: Unamortized discount and premium	(17)	(13)
Less: Unamortized debt issuance costs	(62)	(45)
Less: Maturities due within one year	(17)	(350)
Long-term debt, net	\$ 7,671	\$ 5,991

	2024	2023
Ameren Illinois:		
Bonds and notes:		
3.25% Senior secured notes due 2025 ^(a)	\$ 300	\$ 300
6.125% Senior secured notes due 2028 ^(a)	60	60
3.80% First mortgage bonds due 2028 ^(a)	430	430
1.55% First mortgage bonds due 2030 ^(a)	375	375
3.85% First mortgage bonds due 2032 ^(a)	500	500
4.95% First mortgage bonds due 2033 ^(a)	500	500
6.70% Senior secured notes due 2036 ^(a)	61	61
6.70% Senior secured notes due 2036 ^(a)	42	42
4.80% Senior secured notes due 2043 ^(a)	280	280
4.30% Senior secured notes due 2044 ^(a)	250	250
4.15% Senior secured notes due 2046 ^(a)	490	490
3.70% First mortgage bonds due 2047 ^(a)	500	500
4.50% First mortgage bonds due 2049 ^(a)	500	500
3.25% First mortgage bonds due 2050 ^(a)	300	300
2.90% First mortgage bonds due 2051 ^(a)	350	350
5.90% First mortgage bonds due 2052 ^(a)	350	350
5.55% First mortgage bonds due 2054 ^(a)	625	—
Total long-term debt, gross	5,913	5,288
Less: Long-term debt – related parties, gross	(3)	—
Less: Unamortized discount and premium	(10)	(9)
Less: Unamortized debt issuance costs	(51)	(47)
Less: Maturities due within one year	(300)	—
Long-term debt, net	\$ 5,549	\$ 5,232
ATXI:		
2.45% Senior unsecured notes due 2036 ^(a)	\$ 75	\$ 75
5.17% Senior unsecured notes due 2039	70	—
3.43% Senior unsecured notes due 2050 ⁽ⁱ⁾	351	400
2.96% Senior unsecured notes due 2052 ^(j)	95	95
5.42% Senior unsecured notes due 2053	70	—
Total long-term debt, gross	661	570
Less: Unamortized debt issuance costs	(2)	(2)
Less: Maturities due within one year	—	(49)
Long-term debt, net	\$ 659	\$ 519
Ameren consolidated long-term debt, net	\$ 17,262	\$ 15,121

- (a) These notes are collateralized by first mortgage bonds issued by Ameren Missouri under the Ameren Missouri mortgage indenture. The notes have a fall-away lien provision and will remain secured only as long as any first mortgage bonds issued under the Ameren Missouri mortgage indenture remain outstanding. Redemption, purchase, or maturity of all first mortgage bonds, including first mortgage bonds currently outstanding and any that may be issued in the future, would result in a release of the first mortgage bonds currently securing these notes, at which time these notes would become unsecured obligations. Considering the 2055 maturity date of the 5.125% first mortgage bonds and the restrictions preventing a release date to occur that are attached to certain senior secured notes described in footnote (d) below, Ameren Missouri does not expect the first mortgage lien protection associated with these notes to fall away.
- (b) These bonds are first mortgage bonds issued by Ameren Missouri under the Ameren Missouri mortgage indenture. They are secured by substantially all Ameren Missouri property and franchises.
- (c) These bonds are collateralized by first mortgage bonds issued by Ameren Missouri under the Ameren Missouri mortgage indenture and have a fall-away lien provision similar to that of Ameren Missouri's senior secured notes.
- (d) Ameren Missouri has agreed that so long as any of the 3.90% senior secured notes due 2042 are outstanding, Ameren Missouri will not permit a release date to occur, and so long as any of the 8.45% senior secured notes due 2039 are outstanding, Ameren Missouri will not optionally redeem, purchase, or otherwise retire in full the outstanding first mortgage bonds not subject to release provisions.
- (e) These bonds were issued by AMF. The bondholders of AMF have no recourse to Ameren Missouri's assets. Ameren Missouri collects securitization surcharges to cover the principal and interest on the bonds as well as certain other qualified costs. The surcharges collected by Ameren Missouri on behalf of AMF are remitted to AMF and are not available to creditors of Ameren Missouri. Principal and interest payments on these bonds are payable semiannually on April 1 and October 1 of each year, beginning October 1, 2025, with final principal and interest payment due October 1, 2039.
- (f) These notes are collateralized by first mortgage bonds issued by Ameren Illinois under the Ameren Illinois mortgage indenture. The notes have a fall-away lien provision and will remain secured only as long as any first mortgage bonds issued under the Ameren Illinois mortgage indenture remain outstanding. Redemption, purchase, or maturity of all first mortgage bonds, including first mortgage bonds currently outstanding and any that may be issued in the future, would result in a release of the first mortgage bonds currently securing these notes, at which time these notes would become unsecured obligations. Considering the 2054 maturity date of the 5.55% first mortgage bonds, Ameren Illinois does not expect the first mortgage lien protection associated with these notes to fall away.
- (g) These bonds are first mortgage bonds issued by Ameren Illinois under the Ameren Illinois mortgage indenture. They are secured by substantially all Ameren Illinois property and franchises.
- (h) The following table presents the principal maturities schedule for the 2.45% senior unsecured notes due 2036:

Payment Date	Principal Payment
November 2029	\$ 30
November 2036	45
Total	\$ 75

- (i) The following table presents the principal maturities schedule for the 3.43% senior unsecured notes due 2050:

Payment Date	Principal Payment
August 2027	\$ 50
August 2030	49
August 2032	50
August 2038	49
August 2043	77
August 2050	76
Total	\$ 351

- (j) The following table presents the principal maturities schedule for the 2.96% senior unsecured notes due 2052:

Payment Date	Principal Payment
August 2040	\$ 45
August 2052	50
Total	\$ 95

The following table presents the aggregate maturities of long-term debt, including current maturities, at December 31, 2024:

	Ameren (parent) ^(a)	Ameren Missouri ^(a)	Ameren Illinois ^(a)	ATXI ^(a)	Ameren Consolidated ^(a)
2025	\$ —	\$ 17	\$ 300	\$ —	\$ 317
2026	950	24	—	—	974
2027	500	424	—	50	974
2028	450	26	490	—	966
2029	700	477	—	30	1,207
Thereafter	800	6,857	5,123	581	13,361
Total	\$ 3,400	\$ 7,825	\$ 5,913	\$ 661	\$ 17,799

- (a) Excludes unamortized discount, premium, and debt issuance costs of \$17 million, \$79 million, \$61 million, and \$2 million at Ameren (parent), Ameren Missouri, Ameren Illinois, and ATXI, respectively.

In November and December 2024, Ameren (parent) purchased senior secured notes and first mortgage bonds issued by Ameren Missouri and first mortgage bonds issued by Ameren Illinois for \$44 million in the aggregate. On a consolidated basis, Ameren (parent)'s repurchase of these senior secured notes and first mortgage bonds were accounted for as a debt extinguishment and resulted in

a pre-tax gain of \$16 million, which is reflected in "Other Income, Net" on Ameren's consolidated statement of income. Interest expense related to the repurchased bonds was less than \$1 million for the year ended December 31, 2024.

The following table presents Ameren Missouri's and Ameren Illinois' "Long-term Debt, Net - Related Parties" as of December 31, 2024 and 2023:

	2024	2023
Ameren Missouri:		
3.65% Senior secured notes due 2045	\$ 7	\$ —
3.25% First mortgage bonds due 2049	33	—
2.625% First mortgage bonds due 2051	4	—
3.90% First mortgage bonds due 2052	14	—
Total long-term debt - related parties, gross	58	—
Less: Unamortized debt issuance costs	(1)	—
Long-term debt - related parties, net	\$ 57	\$ —
Ameren Illinois:		
3.70% First mortgage bonds due 2047	\$ 1	\$ —
3.25% First mortgage bonds due 2050	2	—
Long-term debt - related parties, net	\$ 3	\$ —

All classes of Ameren Missouri's and Ameren Illinois' preferred stock are entitled to cumulative dividends, have voting rights, and are not subject to mandatory redemption. The preferred stock of Ameren's subsidiaries is included in "Noncontrolling Interests" on Ameren's consolidated balance sheet. The following table presents the outstanding preferred stock of Ameren Missouri and Ameren Illinois, which is redeemable at the option of the issuer, at the prices shown below as of December 31, 2024 and 2023:

	Shares Outstanding	Redemption Price (per share)	2024	2023
Ameren Missouri:				
Without par value and stated value of \$100 per share, 25 million shares authorized				
\$3.50 Series	130,000 shares	\$ 110.00	\$ 13	\$ 13
\$3.70 Series	40,000 shares	104.75	4	4
\$4.00 Series	150,000 shares	105.625	15	15
\$4.30 Series	40,000 shares	105.00	4	4
\$4.50 Series	213,595 shares	110.00 ^(a)	21	21
\$4.56 Series	200,000 shares	102.47	20	20
\$4.75 Series	20,000 shares	102.176	2	2
\$5.50 Series A	14,000 shares	110.00	1	1
Total			\$ 80	\$ 80
Ameren Illinois:				
With par value of \$100 per share, 2 million shares authorized				
4.00% Series	144,275 shares	\$ 101.00	\$ 14	\$ 14
4.08% Series	45,224 shares	103.00	5	5
4.20% Series	23,655 shares	104.00	2	2
4.25% Series	50,000 shares	102.00	5	5
4.26% Series	16,621 shares	103.00	2	2
4.42% Series	16,190 shares	103.00	2	2
4.70% Series	18,429 shares	104.30	2	2
4.90% Series	73,825 shares	102.00	7	7
4.92% Series	49,289 shares	103.50	5	5
5.16% Series	50,000 shares	102.00	5	5
Total			\$ 49	\$ 49
Total Ameren			\$ 129	\$ 129

(a) In the event of voluntary liquidation, \$105.50.

Ameren has 100 million shares of \$0.01 par value preferred stock authorized, with no such shares outstanding. Ameren Missouri has 7.5 million shares of \$1 par value preference stock authorized, with no such shares outstanding. Ameren Illinois has 2.6 million shares of no par value preferred stock authorized, with no such shares outstanding.

Ameren

Under the DRPlus and its 401(k) plan, Ameren issued 0.5 million, 0.6 million, and 0.5 million shares of common stock in 2024, 2023, and 2022, respectively, received proceeds of \$33 million, \$39 million, and \$41 million for the respective years, and had a receivable of \$7 million and \$7 million as of December 31, 2024 and 2023. In addition, Ameren issued 0.2 million, 0.5 million, and 0.4 million shares of common stock valued at \$16 million, \$40 million, and \$31 million in 2024, 2023, 2022, respectively, for no cash consideration in connection with stock-based compensation.

In May 2023, Ameren filed a Form S-3 registration statement with the SEC, authorizing the offering of 3 million additional shares of its common stock under the DRPlus, which expires in May 2026. Shares of common stock sold under the DRPlus are, at Ameren's option, newly issued shares, treasury shares, or shares purchased in the open market or in privately negotiated contracts.

In October 2023, Ameren, Ameren Missouri, and Ameren Illinois filed a Form S-3 shelf registration statement with the SEC, registering the issuance of an unspecified amount of certain types of securities. This registration statement expires in October 2026.

In May 2022, Ameren filed a Form S-8 registration statement with the SEC, authorizing the offering of 7.5 million additional shares of its common stock under its 401(k) plan. Shares of common stock issuable under the 401(k) plan are, at Ameren's option, newly issued shares, treasury shares, or shares purchased in the open market or in privately negotiated contracts.

Ameren has entered into an equity distribution sales agreement pursuant to which Ameren may offer and sell from time to time up to \$1.75 billion of its common stock through an ATM program, which includes the ability to enter into forward sale agreements. Under the ATM, Ameren issued 2.9 million, 3.2 million, and 3.4 million shares of common stock and received proceeds of \$233 million, \$299 million, and \$292 million in 2024, 2023 and 2022, respectively. These proceeds were net of \$2 million, \$3 million and \$3 million, respectively, in compensation paid to selling agents. As of December 31, 2024, Ameren had approximately \$550 million of common stock available for sale under the ATM program, which takes into account the forward sale agreements in effect as of December 31, 2024 discussed below.

The forward sale agreements outstanding as of December 31, 2024, can be settled at Ameren's discretion on or prior to dates ranging from January 23, 2026 to March 6, 2026. On a settlement date or dates, if Ameren elects to physically settle a forward sale agreement, Ameren will issue shares of common stock to the counterparties at the then-applicable forward sale price. The initial forward sale price for the agreements ranged from \$81.00 to \$93.06, with an average initial forward sale price of \$84.14. Each forward sale price is subject to adjustment based on a floating interest rate factor equal to the overnight bank funding rate less a spread of 75 basis points, and will be subject to decrease on certain dates specified in the forward sale agreements by specified amounts related to expected dividends on shares of the common stock during the term of the forward sale agreements. If the overnight bank funding rate is less than or more than the spread on any day, the interest rate factor will result in a reduction or an increase, respectively, of the forward sale price. The forward sale agreements will be physically settled unless Ameren elects to settle in cash or to net share settle. At December 31, 2024, Ameren could have settled the forward sale agreements with physical delivery of 2.5 million shares of common stock to the respective counterparties in exchange for cash of \$213 million. Alternatively, the forward sale agreements could have also been settled at December 31, 2024, with delivery of approximately \$13 million of cash or approximately 0.1 million shares of common stock to the counterparties. In connection to the forward sale agreements, the various counterparties, or their affiliates, borrowed from third parties and sold 2.5 million shares of common stock. The gross sales price of these shares totaled \$215 million. Ameren does not receive any proceeds from such sales of borrowed shares. The forward sale agreements have been classified as equity transactions.

In January 2025, Ameren entered into a forward sale agreement under the ATM program related to 0.6 million shares of common stock. The January 2025 forward sale agreement can be settled at Ameren's discretion on or prior to February 9, 2026. The forward sale price was initially \$87.43 for the January 2025 forward sale agreement.

In September 2024, \$450 million principal amount of Ameren (parent)'s 2.50% senior unsecured notes matured and was repaid with commercial paper borrowings.

In November 2023, Ameren (parent) issued \$600 million of 5.70% senior unsecured notes due December 2026, with interest payable semiannually on June 1 and December 1 of each year, beginning June 1, 2024. Net proceeds from this issuance were used to repay short-term debt.

In December 2023, Ameren (parent) issued \$700 million of 5.00% senior unsecured notes due January 2029, with interest payable semiannually on January 15 and July 15 of each year, beginning July 15, 2024. Net proceeds from this issuance were used for general corporate purposes, including the repayment of short-term debt.

Ameren Missouri

In January 2024, Ameren Missouri issued \$350 million of 5.25% first mortgage bonds due January 2054, with interest payable semiannually on January 15 and July 15 of each year, beginning July 15, 2024. Net proceeds from this issuance were used for capital expenditures and to repay short-term debt.

In April 2024, Ameren Missouri issued \$500 million of 5.20% first mortgage bonds due April 2034, with interest payable semiannually on April 1 and October 1 of each year, beginning October 1, 2024. Net proceeds from this issuance were used for capital expenditures and to repay short-term debt.

In April 2024, \$350 million principal amount of Ameren Missouri's 3.50% senior secured notes matured and was repaid with cash on hand.

In October 2024, Ameren Missouri issued \$450 million of 5.125% first mortgage bonds due March 2055, with interest payable semiannually on March 15 and September 15 of each year, beginning March 15, 2025. Net proceeds from this issuance were used for capital expenditures and to repay short-term debt.

In December 2024, AMF issued \$476 million of 4.85% securitized utility tariff bonds due October 2039, with principal and interest payable semiannually on April 1 and October 1 of each year, beginning October 1, 2025. Net proceeds from this issuance were used to finance energy transition costs related to the accelerated retirement of the Rush Island Energy Center, which included the remaining unrecovered net plant balance associated with the facility, among other costs, and to repay short-term debt. See Note 2 – Rate and Regulatory Matters for additional information on the securitization of Rush Island Energy Center costs.

In January 2023, Ameren Missouri and Audrain County mutually agreed to terminate a financing obligation agreement related to the CT energy center in Audrain County, which was scheduled to expire in December 2023. No cash was exchanged in connection with the termination of the agreement as the \$240 million principal amount of the financing obligation due from Ameren Missouri was equal to the amount of bond service payments due to Ameren Missouri. Ownership of the energy center was transferred to Ameren Missouri in January 2023, at which time the property, plant, and equipment became subject to the lien of the Ameren Missouri mortgage bond indenture.

In March 2023, Ameren Missouri issued \$500 million of 5.45% first mortgage bonds due March 2053, with interest payable semiannually on March 15 and September 15 of each year, beginning September 15, 2023. Net proceeds from this issuance were used for capital expenditures and to repay short-term debt.

For information on Ameren Missouri's capital contributions, refer to Capital Contributions in Note 13 – Related-party Transactions.

Ameren Illinois

In June 2024, Ameren Illinois issued \$625 million of 5.55% first mortgage bonds due July 2054, with interest payable semiannually on January 1 and July 1 of each year, beginning January 1, 2025. Net proceeds from this issuance were used to repay short-term debt.

In May 2023, Ameren Illinois issued \$500 million of 4.95% first mortgage bonds due June 2033, with interest payable semiannually on June 1 and December 1 of each year, beginning December 1, 2023. Net proceeds from this issuance were used to repay \$100 million principal amount of its 0.375% first mortgage bonds that matured in June 2023 and short-term debt.

For information on Ameren Illinois' capital contributions, refer to Capital Contributions in Note 13 – Related-party Transactions.

ATXI

In August 2024, ATXI issued \$70 million of 5.17% senior unsecured notes due September 2039 and \$70 million of 5.42% senior unsecured notes due September 2053, pursuant to an August 2024 note purchase agreement. Both series of senior unsecured notes have interest payable semiannually on March 1 and September 1 of each year, beginning March 1, 2025, and were issued through a private placement offering exempt from registration under the Securities Act of 1933, as amended. Net proceeds from these issuances were used to repay a \$49 million principal payment of ATXI's 3.43% senior unsecured notes at maturity and to repay short-term debt.

Indenture Provisions and Other Covenants

Ameren Missouri's and Ameren Illinois' indentures and articles of incorporation include covenants and provisions related to issuances of first mortgage bonds and preferred stock. Ameren Missouri and Ameren Illinois are required to meet certain ratios to issue additional first mortgage bonds and preferred stock. A failure to achieve these ratios would not result in a default under these covenants and provisions but would restrict the companies' ability to issue bonds or preferred stock. The following table summarizes the required and actual interest coverage ratios for interest charges, dividend coverage ratios, and bonds and preferred stock issuable as of December 31, 2024, at an assumed interest rate of 7% and dividend rate of 8%.

	Required Interest Coverage Ratio ^(a)	Actual Interest Coverage Ratio	Bonds Issuable ^(b)	Required Dividend Coverage Ratio ^(c)	Actual Dividend Coverage Ratio	Preferred Stock Issuable
Ameren Missouri	≥2.0	2.4	\$2,283	≥2.5	164.4	\$2,769
Ameren Illinois	≥2.0	6.8	9,225	≥1.5	3.5	203 ^(d)

(a) Coverage required on the annual interest charges on first mortgage bonds outstanding and to be issued. Coverage is not required in certain cases when additional first mortgage bonds are issued on the basis of retired bonds.

(b) Amount of bonds issuable based either on required coverage ratios or unfunded property additions, whichever is more restrictive. The amounts shown also include bonds issuable based on retired bond capacity of \$1,509 million and \$1,143 million at Ameren Missouri and Ameren Illinois, respectively.

(c) Coverage required on the annual dividend on preferred stock outstanding and to be issued, as required in the respective company's articles of incorporation.

(d) Preferred stock issuable is restricted by the amount of preferred stock that is currently authorized by Ameren Illinois' articles of incorporation.

Ameren's indenture does not require Ameren to comply with any quantitative financial covenants. The indenture does, however, include certain cross-default provisions. Specifically, either (1) the failure by Ameren to pay when due and upon expiration of any applicable grace period any portion of any Ameren indebtedness in excess of \$25 million, or (2) the acceleration upon default of the maturity of any Ameren indebtedness in excess of \$25 million under any indebtedness agreement, including borrowings under the Credit Agreements or the Ameren commercial paper program, constitutes a default under the indenture, unless such past due or accelerated debt is discharged or the acceleration is rescinded or annulled within a specified period.

Ameren Missouri and Ameren Illinois and certain other nonregistrant Ameren subsidiaries are subject to Section 305(a) of the Federal Power Act, which makes it unlawful for any officer or director of a public utility, as defined in the Federal Power Act, to participate in the making or paying of any dividend from any funds "properly included in capital account." The FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividends are not excessive, and (3) there is no self-dealing on the part of corporate officials. At a minimum, Ameren believes that dividends can be paid by its subsidiaries that are public utilities from net income and retained earnings. In addition, under Illinois law, Ameren Illinois and ATXI may not pay any dividend on their respective stock unless, among other things, their respective earnings and earned surplus are sufficient to declare and pay a dividend after provisions are made for reasonable and proper reserves, or unless Ameren Illinois or ATXI has specific authorization from the ICC.

Ameren Illinois' articles of incorporation require dividend payments on its common stock to be based on ratios of common stock to total capitalization and other provisions related to certain operating expenses and accumulations of earned surplus. Ameren Illinois has made a commitment to the FERC to maintain a minimum 30% ratio of common stock equity to total capitalization. As of December 31, 2024, using the FERC-agreed upon calculation method, Ameren Illinois' ratio of common stock equity to total capitalization was 54%.

ATXI's note purchase agreements includes financial covenants that require ATXI not to permit at any time (1) debt to exceed 70% of total capitalization or (2) secured debt to exceed 10% of total assets.

At December 31, 2024, the Ameren Companies were in compliance with the provisions and covenants contained in their indentures and articles of incorporation, as applicable, and ATXI was in compliance with the provisions and covenants contained in its note purchase agreements. In order for the Ameren Companies to issue securities in the future, they will have to comply with all applicable requirements in effect at the time of any such issuances.

Off-Balance-Sheet Arrangements

At December 31, 2024, none of the Ameren Companies had any material off-balance-sheet financing arrangements, other than their investments in variable interest entities, letters of credit, and the multiple forward sale agreements under the ATM program relating to common stock. See Note 1 – Summary of Significant Accounting Policies for further detail concerning variable interest entities.

NOTE 6 – OTHER INCOME, NET

The following table presents the components of "Other Income, Net" in the Ameren Companies' statements of income for GAAP reporting purposes for the years ended December 31, 2024, 2023, and 2022:

	2024	2023	2022
Ameren:			
Other Income, Net			
Allowance for equity funds used during construction	\$ 76	\$ 54	\$ 43
Interest income on industrial development revenue bonds	—	1	24
Other interest income	41	32	11
Non-service cost components of net periodic benefit income ^(a)	304	295	184
Miscellaneous income	9	7	10
Gain on extinguishment of debt ^(b)	16	—	—
Earnings (losses) related to equity method investments	(4)	1	2
Donations	(5)	(24)	(26)
Miscellaneous expense	(20)	(18)	(22)
Total Other Income, Net	\$ 417	\$ 348	\$ 226
Ameren Missouri:			
Other Income, Net			
Allowance for equity funds used during construction	\$ 58	\$ 30	\$ 24
Interest income on industrial development revenue bonds	—	1	24
Other interest income	8	10	4
Non-service cost components of net periodic benefit income ^(a)	139	97	55
Miscellaneous income	4	3	4
Donations	(2)	(2)	(3)
Miscellaneous expense	(11)	(9)	(9)
Total Other Income, Net	\$ 196	\$ 130	\$ 99
Ameren Illinois:			
Other Income, Net			
Allowance for equity funds used during construction	\$ 17	\$ 19	\$ 18
Other Interest income	32	21	7
Non-service cost components of net periodic benefit income	105	124	84
Miscellaneous income	4	4	5
Donations	(3)	(4)	(8)
Miscellaneous expense	(8)	(8)	(10)
Total Other Income, Net	\$ 147	\$ 156	\$ 96

(a) For the years ended December 31, 2024, 2023, and 2022, the non-service cost components of net periodic benefit income were adjusted by amounts deferred of \$(41) million, \$27 million, and \$22 million, respectively, due to a regulatory tracking mechanism for the difference between the level of such costs incurred by Ameren Missouri under GAAP and the level of such costs included in rates. See Note 10 – Retirement Benefits for additional information.

(b) See Note 5 – Long-term Debt and Equity Financings for additional information on Ameren (parent)'s repurchase of Ameren Missouri's senior secured notes and first mortgage bonds and Ameren Illinois' first mortgage bonds that were accounted for as a debt extinguishment.

NOTE 7 – DERIVATIVE FINANCIAL INSTRUMENTS

We use derivatives to manage the risk of changes in market prices for natural gas, power, uranium, and interest rates, as well as the risk of changes in rail transportation surcharges through fuel oil hedges. Such price fluctuations may cause the following:

- an unrealized appreciation or depreciation of our contracted commitments to purchase or sell when purchase or sale prices under the commitments are compared with current commodity prices;
- market values of natural gas and uranium inventories that differ from the cost of those commodities in inventory;
- actual cash outlays for interest expense and the purchase of commodities that differ from anticipated cash outlays; and
- actual off-system sales revenues that differ from anticipated revenues.

The derivatives that we use to hedge these risks are governed by our risk management policies for forward contracts, futures, options, and swaps. Our net positions are continually assessed within our structured hedging programs to determine whether new or offsetting transactions are required. The goal of the hedging program is generally to mitigate financial risks while ensuring that sufficient volumes are available to meet our requirements. Contracts we enter into as part of our risk management program may be settled financially, settled by physical delivery, or net settled with the counterparty.

All contracts considered to be derivative instruments are required to be recorded on the balance sheet at their fair values, unless the NPNS exception applies. See Note 8 – Fair Value Measurements for discussion of our methods of assessing the fair value of derivative instruments. Many of our physical contracts, such as our purchased power contracts, qualify for the NPNS exception to derivative accounting rules. The revenue or expense on NPNS contracts is recognized at the contract price upon physical delivery. The following disclosures exclude NPNS contracts and other non-derivative commodity contracts that are accounted for under the accrual method of accounting.

If we determine that a contract meets the definition of a derivative and is not eligible for the NPNS exception, we review the contract to determine whether the resulting gains or losses qualify for regulatory deferral. Derivative contracts that qualify for regulatory deferral are recorded at fair value, with changes in fair value recorded as regulatory assets or liabilities in the period in which the change occurs. We believe derivative losses and gains deferred as regulatory assets and liabilities are probable of recovery, or refund, through future rates charged to customers. Regulatory assets and liabilities are amortized to operating income as related losses and gains are reflected in rates charged to customers. Therefore, gains and losses on these derivatives have no effect on operating income. As of December 31, 2024 and 2023, all commodity contracts that met the definition of a derivative and were not eligible for the NPNS exception received regulatory deferral. Interest rate hedges discussed below do not receive regulatory deferral and were included in accumulated OCI. The cash flows from our derivative financial instruments follow the cash flow classification of the hedged item.

In 2024, Ameren (parent) entered into interest rate swaps to hedge a portion of our interest rate risk on cash flows related to forecasted debt issuances through 2026. The interest rate swaps are designated as cash flow hedges and the corresponding changes in fair value each period are initially recorded on the balance sheet in "Accumulated other comprehensive loss" and reclassified into earnings when the debt is issued and the corresponding interest payments affect earnings during the debt term. At December 31, 2024, Ameren had interest rate swaps with notional amounts of \$140 million. The changes in fair value of the interest rate swaps were immaterial at December 31, 2024.

The following table presents open gross commodity contract volumes by commodity type for derivative assets and liabilities as of December 31, 2024 and 2023. As of December 31, 2024, these contracts extended through October 2028, October 2029, and May 2032 for fuel oils, natural gas, and power, respectively.

Commodity	Quantity (in millions, except as indicated)					
	2024			2023		
	Ameren Missouri	Ameren Illinois	Ameren	Ameren Missouri	Ameren Illinois	Ameren
Fuel oils (in gallons)	23	—	23	17	—	17
Natural gas (in mmbtu)	45	213	258	53	218	271
Power (in MWhs)	—	4	4	—	5	5
Uranium (pounds in thousands)	—	—	—	186	—	186

The following table presents the carrying value and balance sheet location of all derivative commodity contracts, none of which were designated as hedging instruments, as of December 31, 2024 and 2023:

Commodity	Balance Sheet Location	2024			2023		
		Ameren Missouri	Ameren Illinois	Ameren	Ameren Missouri	Ameren Illinois	Ameren
Fuel oils	Other current assets	\$ —	\$ —	\$ —	\$ 2	\$ —	\$ 2
	Other assets	—	—	—	—	—	—
Natural gas	Other current assets	2	2	4	—	—	—
	Other assets	2	4	6	3	3	6
Power	Other current assets	6	—	6	5	—	5
	Other assets	—	—	—	—	—	—
Uranium	Other current assets	—	—	—	9	—	9
	Other assets	—	—	—	—	—	—
	Total assets	\$ 10	\$ 6	\$ 16	\$ 19	\$ 3	\$ 22
Fuel oils	Other current liabilities	\$ 2	\$ —	\$ 2	\$ 1	\$ —	\$ 1
	Other deferred credits and liabilities	2	—	2	1	—	1
Natural gas	Other current liabilities	5	22	27	12	45	57
	Other deferred credits and liabilities	6	13	19	10	30	40
Power	Other current liabilities	—	10	10	1	12	13
	Other deferred credits and liabilities	—	43	43	—	56	56
	Total liabilities	\$ 15	\$ 88	\$ 103	\$ 25	\$ 143	\$ 168

The Ameren Companies elect to present the fair value amounts of derivative assets and derivative liabilities subject to an enforceable master netting arrangement or similar agreement at the gross amounts on the balance sheet. However, if the gross amounts recognized on the balance sheet were netted with derivative instruments and cash collateral received or posted, the net amounts would not be materially different from the gross amounts at December 31, 2024 and 2023.

Credit Risk

In determining our concentrations of credit risk related to derivative instruments, we review our individual counterparties and categorize each counterparty into groupings according to the primary business in which each engages. As of December 31, 2024, if counterparty groups were to fail completely to perform on contracts, the Ameren Companies' maximum exposure related to derivative assets, predominantly from financial institutions, would have been immaterial with or without consideration of the application of master netting arrangements or similar agreements and collateral held.

Certain of our derivative instruments contain collateral provisions tied to the Ameren Companies' credit ratings. If our credit ratings were downgraded below investment grade, or if a counterparty with reasonable grounds for uncertainty regarding our ability to satisfy an obligation requested adequate assurance of performance, additional collateral postings might be required. The additional collateral required is the net liability position allowed under the master netting arrangements or similar agreements, assuming (1) the credit risk-related contingent features underlying these arrangements were triggered and (2) those counterparties with rights to do so requested collateral. As of December 31, 2024, the aggregate fair value of derivative instruments with credit risk-related contingent features in a gross liability position, the cash collateral posted, and the aggregate amount of additional collateral that counterparties could require were each immaterial to Ameren, Ameren Missouri, and Ameren Illinois.

NOTE 8 – FAIR VALUE MEASUREMENTS

Fair value is defined as the price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. We use various methods to determine fair value, including market, income, and cost approaches. With these approaches, we adopt certain assumptions that market participants would use in pricing the asset or liability, including assumptions about market risk or the risks inherent in the inputs to the valuation. Inputs to valuation can be readily observable, market-corroborated, or unobservable. We use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. Authoritative accounting guidance established a fair value hierarchy that prioritizes the inputs used to measure fair value. All financial assets and liabilities carried at fair value are classified and disclosed in one of the following three hierarchy levels:

Level 1 (quoted prices in active markets for identical assets or liabilities): Inputs based on quoted prices in active markets for identical assets or liabilities. Level 1 assets and liabilities are primarily exchange-traded derivatives, cash and cash equivalents, and listed equity securities.

The market approach is used to measure the fair value of equity securities held in Ameren Missouri's nuclear decommissioning trust fund. Equity securities in this fund are representative of the S&P 500 index, excluding securities of Ameren Corporation, owners and/or operators of nuclear power plants, and the trustee and investment managers. The S&P 500 index comprises stocks of large-capitalization companies.

Level 2 (significant other observable inputs): Market-based inputs corroborated by third-party brokers or exchanges based on transacted market data. Level 2 assets and liabilities include certain assets held in Ameren Missouri's nuclear decommissioning trust fund, including United States Treasury and agency securities, corporate bonds and other fixed-income securities, and certain over-the-counter derivative instruments, including natural gas and financial power transactions.

Fixed income securities are valued by using prices from independent industry-recognized data vendors who provide values that are either exchange-based or matrix-based. The fair value measurements of fixed-income securities classified as Level 2 are based on inputs other than quoted prices that are observable for the asset or liability. Examples are matrix pricing, market corroborated pricing, and inputs such as yield curves and indices.

Derivative instruments classified as Level 2 are valued by corroborated observable inputs, such as pricing services or prices from similar instruments that trade in liquid markets. Our development and corroboration process entails obtaining multiple quotes or prices from outside sources. To derive our forward view to price our derivative instruments at fair value, we average the bid/ask spreads to the midpoints. Additionally, a review of all sources is performed to identify any anomalies or potential errors. Further, we consider the volume of transactions on certain trading platforms in our reasonableness assessment of the averaged midpoints. The value of natural gas derivative contracts is based upon exchange closing prices without significant unobservable adjustments. The value of power derivative contracts is based upon exchange closing prices or the use of multiple forward prices provided by third parties.

Level 3 (significant other unobservable inputs): Unobservable inputs that are not corroborated by market data. Level 3 assets and liabilities are valued by internally developed models and assumptions or methodologies that use significant unobservable inputs. Level 3 assets and liabilities include derivative instruments that trade in less liquid markets, where pricing is largely unobservable. We value Level 3 instruments by using pricing models with inputs that are often unobservable in the market, such as certain internal assumptions, quotes or prices from outside sources not supported by a liquid market, or trend rates.

We perform an analysis each quarter to determine the appropriate hierarchy level of the assets and liabilities subject to fair value measurements. Financial assets and liabilities are classified in their entirety according to the lowest level of input that is significant to the fair value measurement. All assets and liabilities whose fair value measurement is based on significant unobservable inputs are classified as Level 3.

We consider nonperformance risk in our valuation of derivative instruments by analyzing our own credit standing and the credit standing of our counterparties, and by considering any credit enhancements (e.g., collateral). Included in our valuation, and based on current market conditions, is a valuation adjustment for counterparty default derived from market data such as the price of credit default swaps, bond yields, and credit ratings. No material gains or losses related to valuation adjustments for counterparty default risk were recorded at Ameren, Ameren Missouri, or Ameren Illinois in 2024, 2023, or 2022. At December 31, 2024 and 2023, the counterparty default risk valuation adjustment related to derivative contracts was immaterial for Ameren, Ameren Missouri, and Ameren Illinois.

The following table sets forth, by level within the fair value hierarchy, our assets and liabilities measured at fair value on a recurring basis as of December 31, 2024 and 2023:

	December 31, 2024				December 31, 2023			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Ameren Missouri								
Derivative assets – commodity contracts:								
Fuel oils	\$ —	\$ —	\$ —	\$ —	\$ 2	\$ —	\$ —	\$ 2
Natural gas	—	4	—	4	—	3	—	3
Power	—	—	6	6	—	—	5	5
Uranium	—	—	—	—	—	—	9	9
Total derivative assets – commodity contracts	\$ —	\$ 4	\$ 6	\$ 10	\$ 2	\$ 3	\$ 14	\$ 19
Nuclear decommissioning trust fund:								
Equity securities:								
U.S. large capitalization	\$ 911	\$ —	\$ —	\$ 911	\$ 787	\$ —	\$ —	\$ 787
Debt securities:								
U.S. Treasury and agency securities	—	191	—	191	—	150	—	150
Corporate bonds	—	145	—	145	—	136	—	136
Other	—	86	—	86	—	68	—	68
Total nuclear decommissioning trust fund	\$ 911	\$ 422	\$ —	\$ 1,333 ^(a)	\$ 787	\$ 354	\$ —	\$ 1,141 ^(a)
Total Ameren Missouri	\$ 911	\$ 426	\$ 6	\$ 1,343	\$ 789	\$ 357	\$ 14	\$ 1,160
Ameren Illinois								
Derivative assets – commodity contracts:								
Natural gas	\$ —	\$ 3	\$ 3	\$ 6	\$ —	\$ 1	\$ 2	\$ 3
Total Ameren Illinois	\$ —	\$ 3	\$ 3	\$ 6	\$ —	\$ 1	\$ 2	\$ 3
Ameren								
Derivative assets – commodity contracts ^(b)								
	\$ —	\$ 7	\$ 9	\$ 16	\$ 2	\$ 4	\$ 16	\$ 22
Nuclear decommissioning trust fund ^(c)	911	422	—	1,333 ^(a)	787	354	—	1,141 ^(a)
Total Ameren	\$ 911	\$ 429	\$ 9	\$ 1,349	\$ 789	\$ 358	\$ 16	\$ 1,163
Liabilities:								
Ameren Missouri								
Derivative liabilities – commodity contracts:								
Fuel oils	\$ 4	\$ —	\$ —	\$ 4	\$ 2	\$ —	\$ —	\$ 2
Natural gas	—	11	—	11	—	19	3	22
Power	—	—	—	—	—	—	1	1
Total Ameren Missouri	\$ 4	\$ 11	\$ —	\$ 15	\$ 2	\$ 19	\$ 4	\$ 25
Ameren Illinois								
Derivative liabilities – commodity contracts:								
Natural gas	\$ 1	\$ 28	\$ 6	\$ 35	\$ 4	\$ 60	\$ 11	\$ 75
Power	—	—	53	53	—	—	68	68
Total Ameren Illinois	\$ 1	\$ 28	\$ 59	\$ 88	\$ 4	\$ 60	\$ 79	\$ 143
Ameren								
Derivative liabilities – commodity contracts ^(b)								
	\$ 5	\$ 39	\$ 59	\$ 103	\$ 6	\$ 79	\$ 83	\$ 168

(a) Balance excludes \$9 million and \$9 million of cash and cash equivalents, receivables, payables, and accrued income, net for December 31, 2024 and 2023, respectively.

(b) See the Ameren Missouri and Ameren Illinois sections of the table for the fair value of Ameren's derivative assets and liabilities by type of commodity.

(c) See the Ameren Missouri section of the table for Ameren's nuclear decommissioning trust fund by investment type.

See Note 10 – Retirement Benefits for tables that set forth, by level within the fair value hierarchy, Ameren's pension and postretirement plan assets as of December 31, 2024 and 2023.

Level 3 fuel oils, natural gas and uranium derivative contract assets and liabilities measured at fair value on a recurring basis were immaterial for all periods presented. The following table presents the fair value reconciliation of Level 3 power derivative contract assets and liabilities measured at fair value on a recurring basis for the years ended December 31, 2024 and 2023:

	2024			2023		
	Ameren Missouri	Ameren Illinois	Ameren	Ameren Missouri	Ameren Illinois	Ameren
Beginning balance at January 1	\$ 4	\$(68)	\$(64)	\$ 12	\$(33)	\$(21)
Realized and unrealized gains (losses) included in regulatory assets/liabilities	12	(1)	11	1	(48)	(47)
Settlements	(10)	16	6	(9)	13	4
Ending balance at December 31	\$ 6	\$(53)	\$(47)	\$ 4	\$(68)	\$(64)
Change in unrealized gains (losses) related to assets/liabilities held at December 31	6	3	9	4	(36)	(32)

All gains or losses related to our Level 3 derivative commodity contracts are expected to be recovered or returned through customer rates; therefore, there is no impact to either net income or OCI resulting from changes in the fair value of these instruments.

The following table describes the valuation techniques and significant unobservable inputs utilized for the fair value of our Level 3 power derivative contract assets and liabilities as of December 31, 2024 and 2023:

	Commodity	Fair Value		Valuation Technique(s)	Unobservable Input ^(a)	Range	Weighted Average ^(b)
		Assets	Liabilities				
2024	Power ^(c)	\$ 6	\$(53)	Discounted cash flow	Average forward peak and off-peak pricing – forwards/swaps (\$/MWh)	32 – 69	45
					Nodal basis (\$/MWh)	(8) – (2)	(5)
2023	Power ^(c)	\$ 5	\$(69)	Discounted cash flow	Average forward peak and off-peak pricing – forwards/swaps (\$/MWh)	31 – 65	43
					Nodal basis (\$/MWh)	(8) – (1)	(5)

(a) Generally, significant increases (decreases) in these inputs in isolation would result in a significantly higher (lower) fair value measurement.

(b) Unobservable inputs were weighted by relative fair value.

(c) Valuations use visible forward prices adjusted for nodal-to-hub basis differentials.

The following table sets forth the carrying amount and, by level within the fair value hierarchy, the fair value of long-term debt (including current portion), disclosed, but not recorded, at fair value as of December 31, 2024 and 2023:

Long-Term Debt (Including Current Portion):	Carrying Amount ^(a)	Fair Value		
		Level 2	Level 3	Total
		December 31, 2024		
Ameren ^(b)	\$ 17,579	\$ 15,395	\$ 538 ^(c)	\$ 15,933
Ameren Missouri ^(d)	7,745	6,926	—	6,926
Ameren Illinois ^(d)	5,852	5,243	—	5,243
		December 31, 2023		
Ameren	\$ 15,970	\$ 14,366	\$ 467 ^(c)	\$ 14,833
Ameren Missouri	6,341	5,800	—	5,800
Ameren Illinois	5,232	4,867	—	4,867

(a) Included unamortized debt issuance costs, which were excluded from the fair value measurement, of \$129 million, \$62 million, and \$51 million for Ameren, Ameren Missouri, and Ameren Illinois, respectively, as of December 31, 2024. Included unamortized debt issuance costs, which were excluded from the fair value measurement, of \$111 million, \$45 million, and \$47 million for Ameren, Ameren Missouri, and Ameren Illinois, respectively, as of December 31, 2023.

(b) Amount excludes Ameren (parent)'s repurchase of Ameren Missouri's senior secured notes and first mortgage bonds and Ameren Illinois' first mortgage bonds in 2024 that were accounted for as a debt extinguishment. See Note 5 – Long-term Debt and Equity Financings for additional information.

(c) The Level 3 fair value amount consists of ATXI's senior unsecured notes.

(d) Amount includes Ameren Missouri's senior secured notes and first mortgage bonds and Ameren Illinois' first mortgage bonds that were repurchased by Ameren (parent) in 2024.

The Ameren Companies' carrying amounts of cash, cash equivalents, and restricted cash approximate fair value and are considered Level 1 in the fair value hierarchy. The Ameren Companies' short-term borrowings approximate fair value because of the short-term nature of these instruments and are considered Level 2 in the fair value hierarchy.

NOTE 9 – CALLAWAY ENERGY CENTER

Spent Nuclear Fuel

Under the Nuclear Waste Policy Act of 1982, as amended, the DOE is responsible for disposing of spent nuclear fuel from the Callaway Energy Center and other commercial nuclear energy centers. As required by the act, Ameren Missouri and other utilities have entered into standard contracts with the DOE, which stated that the DOE would begin to dispose of spent nuclear fuel by 1998. However, the DOE failed to fulfill its disposal obligations, and Ameren Missouri and other nuclear energy center owners sued the DOE to recover costs incurred for ongoing storage of their spent fuel. Ameren Missouri's lawsuit against the DOE resulted in a settlement agreement that provides for annual reimbursement of additional spent fuel storage and related costs. Ameren Missouri received immaterial reimbursements from the DOE in the years ended December 31, 2024, 2023, and 2022. Ameren Missouri will continue to apply for reimbursement from the DOE for allowable costs associated with the ongoing storage of spent fuel. The DOE's delay in carrying out its obligation to dispose of spent nuclear fuel from the Callaway Energy Center is not expected to adversely affect the continued operations of the energy center.

Decommissioning

Electric rates charged to customers provide for the recovery of the Callaway Energy Center's decommissioning costs, which include decontamination, dismantling, and site restoration costs, over the expected life of the nuclear energy center. Amounts collected from customers are deposited into the external nuclear decommissioning trust fund to provide for the Callaway Energy Center's decommissioning. It is assumed that the Callaway Energy Center site will be decommissioned after its retirement through the immediate dismantlement method and removed from service. The Callaway Energy Center's operating license expires in 2044. Ameren and Ameren Missouri have recorded an ARO for the Callaway Energy Center decommissioning costs at fair value. Annual decommissioning costs of \$7 million are included in the costs used to establish electric rates for Ameren Missouri's customers. Every three years, the MoPSC requires Ameren Missouri to file an updated cost study and funding analysis for decommissioning its Callaway Energy Center. An updated cost study and funding analysis was filed with the MoPSC in December 2023 and reflected within the ARO. Ameren Missouri's filing supported no change in electric service rates for decommissioning costs. There is no deadline by which the MoPSC must issue an order regarding the filing.

Ameren and Ameren Missouri have classified the investments in debt and equity securities that are held in the nuclear decommissioning trust fund as available for sale, and have recorded all such investments at their fair market value at December 31, 2024 and 2023. Investments in the nuclear decommissioning trust fund have a target allocation of 60% to 70% in equity securities, with the balance invested in debt securities.

The fair value of the trust fund for Ameren Missouri's Callaway Energy Center is reported as "Nuclear decommissioning trust fund" in Ameren's and Ameren Missouri's balance sheets. This amount is legally restricted and may be used only to fund the costs of nuclear decommissioning. Changes in the fair value of the trust fund are recorded as an increase or decrease to the nuclear decommissioning trust fund, with an offsetting adjustment to the regulatory liability related to AROs. This reporting is consistent with the method used to account for the decommissioning costs recovered in rates. See Note 2 – Rate and Regulatory Matters for the regulatory liability recorded at December 31, 2024. If the assumed return on trust assets is not earned, Ameren Missouri believes that it is probable that any additional funding requirements resulting from such earnings deficiency will be recovered in customer rates.

The following table presents proceeds from the sales and maturities of investments in Ameren Missouri's nuclear decommissioning trust fund and the gross realized gains and losses resulting from those sales for the years ended December 31, 2024, 2023, and 2022:

	2024	2023	2022
Proceeds from sales and maturities	\$ 564	\$ 240	\$ 216
Gross realized gains	44	6	40
Gross realized losses	28	11	10

The following table presents the cost and fair value of investments in debt and equity securities in Ameren's and Ameren Missouri's nuclear decommissioning trust fund at December 31, 2024 and 2023:

Security Type	Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
2024				
Debt securities	\$ 437	\$ 2	\$ 17	\$ 422
Equity securities	179	740	8	911
Cash and cash equivalents	10	—	—	10
Other ^(a)	(1)	—	—	(1)
Total	\$ 625	\$ 742	\$ 25	\$ 1,342
2023				
Debt securities	\$ 382	\$ 3	\$ 31	\$ 354
Equity securities	191	603	7	787
Cash and cash equivalents	5	—	—	5
Other ^(a)	4	—	—	4
Total	\$ 582	\$ 606	\$ 38	\$ 1,150

(a) Represents net receivables and payables relating to pending securities sales, interest, and securities purchases.

The following table presents the costs and fair values of investments in debt securities in Ameren's and Ameren Missouri's nuclear decommissioning trust fund according to their contractual maturities at December 31, 2024:

	Cost	Fair Value
Less than 5 years	\$ 186	\$ 184
5 years to 10 years	117	112
Due after 10 years	134	126
Total	\$ 437	\$ 422

Insurance

The following table presents insurance coverage at Ameren Missouri's Callaway Energy Center at January 1, 2025:

Type and Source of Coverage	Most Recent Renewal Date	Maximum Coverages		Maximum Assessments for Single Incidents
Public liability and nuclear worker liability:				
American Nuclear Insurers	January 1, 2025	\$	500	\$ —
Pool participation	(a)		15,763 ^(e)	166 ^(b)
		\$	16,263 ^(c)	\$ 166
Property damage:				
NEIL and EMANI	April 1, 2024	\$	3,200 ^(d)	\$ 28 ^(e)
Accidental outage:				
NEIL	April 1, 2024	\$	490 ^(f)	\$ 11 ^(e)

(a) Provided through mandatory participation in an industrywide retrospective premium assessment program. The maximum coverage available is dependent on the number of United States commercial reactors participating in the program.

(b) Retrospective premium under the Price-Anderson Act. This is subject to retrospective assessment with respect to a covered loss in excess of \$500 million in the event of an incident at any licensed United States commercial reactor, payable at \$25 million per year.

(c) Limit of liability for each incident under the Price-Anderson liability provisions of the Atomic Energy Act of 1954, as amended. This limit is subject to change to account for the effects of inflation and changes in the number of licensed power reactors.

(d) NEIL provides \$2.7 billion in property damage, stabilization, decontamination, and premature decommissioning insurance for radiation events and \$0.7 billion in property damage insurance for nonradiation events. EMANI provides \$490 million in property damage insurance for both radiation and nonradiation events.

(e) All NEIL-insured plants could be subject to assessments should losses exceed the accumulated funds from NEIL.

(f) Accidental outage insurance provides for lost sales in the event of a prolonged accidental outage. Weekly indemnity up to \$4.5 million for 52 weeks, which commences after the first 12 weeks of an outage, plus up to \$3.6 million per week for a minimum of 71 weeks thereafter for a total not exceeding the policy limit of \$490 million. Nonradiation events are limited to \$291 million.

The Price-Anderson Act is a federal law that limits the liability for claims from an incident involving any licensed United States commercial nuclear energy center. The limit is based on the number of licensed reactors. The limit of liability and the maximum potential annual payments are adjusted at least every five years for inflation to reflect changes in the Consumer Price Index. The most recent five-year inflationary adjustment became effective in October 2023. Owners of a nuclear reactor cover this exposure through a combination of private insurance and mandatory participation in a financial protection pool, as established by the Price-Anderson Act.

Losses resulting from terrorist attacks on nuclear facilities insured by NEIL are subject to industrywide aggregates, such that terrorist acts against one or more commercial nuclear power plants within a stated time period would be treated as a single event, and the owners of the nuclear power plants would share the limit of liability. NEIL policies have an aggregate limit of \$3.2 billion within a 12-month period for radiation events, or \$1.8 billion for events not involving radiation contamination, resulting from terrorist attacks. The EMANI policies are not subject to industrywide aggregates in the event of terrorist attacks on nuclear facilities.

If losses from a nuclear incident at the Callaway Energy Center exceed the limits of, or are not covered by insurance, or if coverage is unavailable, Ameren Missouri is at risk for any uninsured losses. If a serious nuclear incident were to occur, it could have a material adverse effect on Ameren's and Ameren Missouri's results of operations, financial position, or liquidity.

NOTE 10 – RETIREMENT BENEFITS

The primary objective of the Ameren pension and postretirement benefit plans is to provide eligible employees with pension and postretirement health care and life insurance benefits. Ameren has defined benefit pension plans covering substantially all of its employees and has a postretirement benefit plan covering non-union employees hired before October 2015 and union employees hired before January 2020. Ameren Missouri and Ameren Illinois each participate in Ameren's single-employer pension and other postretirement plans. All non-union employees participate in a cash balance pension plan. Ameren Missouri union employees hired after June 2013, and Ameren Illinois union employees hired after mid-October 2012, participate in a cash balance pension plan. Ameren uses a measurement date of December 31 for its pension and postretirement benefit plans. Ameren's qualified pension plan is the Ameren Retirement Plan. Ameren's other postretirement plan is the Ameren Retiree Welfare Benefit Plan. Ameren also has an unfunded nonqualified pension plan, the Ameren Supplemental Retirement Plan, which is available to provide certain non-union employees and retirees with a supplemental benefit when their qualified pension plan benefits are capped in compliance with Internal Revenue Code limitations. Only Ameren subsidiaries participate in the plans listed above.

Ameren's pension and other postretirement benefit plans were overfunded by \$734 million and \$551 million in the aggregate as of December 31, 2024 and 2023, respectively. These net assets are recorded in "Pension and other postretirement benefits," "Other current liabilities," and "Other deferred credits and liabilities" on Ameren's consolidated balance sheet. The increase in the overfunded pension and postretirement benefit plans during 2024 was primarily the result of a 45-basis-point increase in the pension and other postretirement benefit plan discount rates used to determine the present value of the obligation and an increase in the actual return on plan assets of the pension and postretirement trusts. The overfunded pension and other postretirement benefit plans also resulted in regulatory liabilities on Ameren's, Ameren Missouri's, and Ameren Illinois' balance sheets.

The following table presents the net benefit liability/(asset) recorded on the balance sheets as of December 31, 2024 and 2023:

	2024		2023	
Ameren ^(a)	\$	(734)	\$	(551)
Ameren Missouri ^(a)		(201)		(142)
Ameren Illinois ^(a)		(438)		(351)

(a) Liabilities associated with pension and other postretirement benefits are recorded in "Other current liabilities" and "Other deferred credits and liabilities" on Ameren's, Ameren Missouri's, and Ameren Illinois' balance sheets.

Ameren recognizes the overfunded and underfunded status of its pension and postretirement plans as an asset or a liability on its consolidated balance sheet, with offsetting entries to accumulated OCI and regulatory assets or liabilities. The following table presents the funded status of Ameren's pension and postretirement benefit plans as of December 31, 2024 and 2023. It also provides the amounts included in regulatory assets or liabilities and accumulated OCI at December 31, 2024 and 2023, that have not been recognized in net periodic benefit costs.

	2024		2023	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
Accumulated benefit obligation at end of year	\$ 3,962	\$ (a)	\$ 4,102	\$ (a)
Change in benefit obligation:				
Net benefit obligation at beginning of year	\$ 4,258	\$ 856	\$ 4,061	\$ 838
Service cost	88	12	79	12
Interest cost	222	44	221	45
Participant contributions	—	7	—	7
Actuarial (gain) loss	(143)	(51)	170	17
Benefits paid	(291)	(61)	(273)	(63)
Net benefit obligation at end of year	4,134	807	4,258	856
Change in plan assets:				
Fair value of plan assets at beginning of year	4,272	1,393	4,027	1,249
Actual return on plan assets	193	150	514	197
Employer contributions	8	4	4	3
Participant contributions	—	7	—	7
Benefits paid	(291)	(61)	(273)	(63)
Fair value of plan assets at end of year	4,182	1,493	4,272	1,393
Funded status – surplus	(48)	(686)	(14)	(537)
Accrued benefit asset at December 31	\$ (48)	\$ (686)	\$ (14)	\$ (537)
Amounts recognized in the balance sheet consist of:				
Noncurrent asset	\$ (71)	\$ (686)	\$ (44)	\$ (537)
Current liability ^(b)	2	—	2	—
Noncurrent liability ^(c)	21	—	28	—
Net asset recognized	\$ (48)	\$ (686)	\$ (14)	\$ (537)
Amounts recognized in regulatory assets or liabilities consist of:				
Net actuarial (gain) loss	\$ 42	\$ (379)	\$ (10)	\$ (311)
Prior service credit	—	(21)	—	(25)
Amounts recognized in accumulated OCI (pretax) consist of:				
Net actuarial (gain) loss	26	(7)	22	(4)
Total	\$ 68	\$ (407)	\$ 12	\$ (340)

(a) Not applicable.

(b) Included in "Other current liabilities" on Ameren's consolidated balance sheet.

(c) Included in "Other deferred credits and liabilities" on Ameren's consolidated balance sheet.

The following table presents the assumptions used to determine our benefit obligations at December 31, 2024 and 2023:

	Pension Benefits		Postretirement Benefits		
	2024	2023	2024	2023	
Discount rate at measurement date	5.70 %	5.25 %	5.70 %	5.25 %	
Increase in future compensation	4.00	3.50 ^(a)	4.00	3.50 ^(a)	
Cash balance pension plan interest crediting rate	5.50	5.50	(b)	(b)	
Medical cost trend rate (initial) ^(c)	(b)	(b)	(d)	(d)	
Medical cost trend rate (ultimate) ^(c)	(b)	(b)	5.00	5.00	

(a) As of December 31, 2023, increase in future compensation was 4.00% in 2024, and 3.50% thereafter.

(b) Not applicable.

(c) Initial and ultimate medical cost trend rate for certain Medicare-eligible participants was 2.50% at December 31, 2024 and 2023.

(d) Initial medical cost trend rates of 7.00% and 6.93% for pre-Medicare plan participants and 7.00% and 6.50% for post-Medicare plan participants at December 31, 2024 and 2023, respectively, trend down to the ultimate rate by 2033 and 2030, respectively, with a 3.00% upward adjustment to the post-Medicare trend rate in 2025.

Ameren determines discount rate assumptions by identifying a theoretical settlement portfolio of high-quality corporate bonds sufficient to provide for a plan's projected benefit payments. The settlement portfolio of bonds is selected from a pool of approximately 860 high-quality corporate bonds. A single discount rate is then determined; that rate results in a discounted value of the plan's benefit payments that equates to the market value of the selected bonds. In 2024, Ameren elected to continue to use the Society of Actuaries mortality table and the Society of Actuaries 2020 Mortality Improvement Scale.

Funding

Pension benefits are based on the employees' years of service, age, and compensation. Ameren's pension plans are funded in compliance with income tax regulations, federal funding requirements, and other regulatory requirements. As a result, Ameren expects to fund its pension plans at a level equal to the greater of the pension cost or the legally required minimum contribution. Based on its assumptions at December 31, 2024, its investment performance in 2024, and its pension funding policy, Ameren does not expect to make material contributions in 2025 and expects to make aggregate contributions of \$170 million in 2026 through 2029. Ameren Missouri and Ameren Illinois estimate that their portion of the future funding requirements will be 40% and 50%, respectively. These estimated contributions may change based on actual investment performance, changes in interest rates, changes in our assumptions, changes in government regulations, and any voluntary contributions. Our funding policy for postretirement benefits is primarily to fund the Voluntary Employee Beneficiary Association (VEBA) trusts to match the annual postretirement expense.

The following table presents the cash contributions made to our defined benefit retirement plans and to our postretirement plan during 2024, 2023, and 2022:

	Pension Benefits			Postretirement Benefits		
	2024	2023	2022	2024	2023	2022
Ameren Missouri	\$ 1	\$ 1	\$ 1	\$ 2	\$ 2	\$ 1
Ameren Illinois	1	2	3	1	1	1
Ameren Services	6	1	1	1	—	—
Ameren	\$ 8	\$ 4	\$ 5	\$ 4	\$ 3	\$ 2

Investment Strategy and Policies

Ameren manages plan assets in accordance with the "prudent investor" guidelines contained in ERISA. The investment committee, which includes members of senior management, approves and implements investment strategy and asset allocation guidelines for the plan assets. The investment committee's goals are twofold: first, to ensure that sufficient funds are available to provide the benefits at the time they are payable; and second, to maximize total return on plan assets and to minimize expense volatility consistent with its tolerance for risk. Ameren delegates the task of investment management to specialists in each asset class. As appropriate, Ameren provides each investment manager with guidelines that specify allowable and prohibited investment types. The investment committee regularly monitors manager performance and compliance with investment guidelines.

The expected return on plan assets assumption is based on historical and projected rates of return for current and planned asset classes in the investment portfolio. Projected rates of return for each asset class were estimated after an analysis of historical experience, future expectations, and the volatility of the various asset classes. After considering the target asset allocation for each asset class, we reviewed the overall expected rate of return for the portfolio for historical and expected experience of active portfolio management results compared with benchmark returns and for the effect of expenses paid from plan assets. Ameren will use an expected return on plan assets for its pension and postretirement plan assets of 6.75% in 2025.

Ameren's investment committee strives to assemble a portfolio of diversified assets that does not create a significant concentration of risks. The investment committee develops asset allocation guidelines between asset classes, and it creates diversification through investments in assets that differ by type (equity, debt, real estate), duration, market capitalization, country, style (growth or value), and industry, among other factors. The diversification of assets is displayed in the target allocation table below. The investment committee also routinely rebalances the plan assets to adhere to the diversification goals. The investment committee's strategy reduces the concentration of investment risk; however, Ameren is still subject to overall market risk.

Ameren's investment committee developed and implemented a liability hedging investment strategy for its qualified pension plan designed to reduce interest rate risk as part of an objective for its long-term investment strategy. The plan invests in derivative instruments mainly consisting of interest rate futures intended to extend the duration of the pension plan assets so that the assets are more closely aligned with the duration of the liabilities. In addition, part of Ameren's investment strategy includes participation in a securities lending program, which allows it to lend eligible securities to third party borrowers. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested in the form of cash, government obligations, and U.S. agency obligations. Ameren's fair value of securities loaned was \$454 million and \$234 million as of December 31, 2024 and 2023, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2024 and 2023.

The following table presents our target allocations and our pension and postretirement plans' asset categories as of December 31, 2024 and 2023:

Asset Category	Target Allocation 2024	Percentage of Plan Assets at December 31,	
		2024	2023
Pension Plan:			
Cash and cash equivalents	0% – 5%	3 %	1 %
Equity securities:			
U.S. large-capitalization	10% – 20%	16 %	15 %
U.S. small- and mid-capitalization	3% – 13%	9 %	8 %
Global	10% – 20%	15 %	16 %
International	4% – 14%	9 %	12 %
Total equity	42% – 52%	49 %	51 %
Debt securities	32% – 42%	35 % ^(a)	35 % ^(a)
Diversified credit	6% – 16%	8 %	7 %
Real estate	0% – 10%	5 %	6 %
Private equity	0% – 5%	(b)	(b)
Total		100 %	100 %
Postretirement Plans:			
Cash and cash equivalents	0% – 7%	2 %	1 %
Equity securities:			
U.S. large-capitalization	23% – 33%	33 %	32 %
U.S. small- and mid-capitalization	3% – 13%	8 %	8 %
Global	9% – 19%	13 %	15 %
International	5% – 15%	8 %	8 %
Total equity	55% – 65%	62 %	63 %
Debt securities	33% – 43%	36 %	36 %
Total		100 %	100 %

(a) Includes interest rate futures derivative instruments.

(b) Less than 1% of plan assets.

In general, the United States large-capitalization equity investments are passively managed or indexed, whereas the international, global, United States small-capitalization, and United States mid-capitalization equity investments are actively managed by investment managers. Debt securities include a broad range of fixed-income vehicles. Debt security investments in high-yield securities and non-United-States-dollar-denominated securities are owned by the plans, but in limited quantities to reduce risk. Most of the debt security investments are under active management by investment managers. Diversified credit investments include but are not limited to, sub-investment grade rated bonds and loans, securitized credit, and emerging market debt. Real estate investments include private real estate vehicles; however, Ameren does not, by policy, hold direct investments in real estate property. In addition to the derivative investments included in the liability hedging investment strategy described above, Ameren's investment committee also allows investment managers to use derivatives, such as index futures, foreign exchange futures, and options, in certain situations to increase or to reduce market exposure in an efficient and timely manner.

Fair Value Measurements of Plan Assets

Investments in the pension and postretirement benefit plans were stated at fair value as of December 31, 2024. Fair value is defined as the price that would be received for an asset in the principal or most advantageous market for the asset in an orderly transaction between market participants on the measurement date. Cash and cash equivalents have initial maturities of three months or less and are recorded at cost plus accrued interest. Investments traded in active markets on national or international securities exchanges are valued at closing prices on the measurement date or, if that is not a business day, on the last business day before that date. Securities traded in over-the-counter markets are valued by quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. Investments measured under NAV as a practical expedient are based on the fair values of the underlying assets provided by the funds and their administrators. The fair value of real estate investments is based on NAV; it is determined by annual appraisal reports prepared by an independent real estate appraiser. Investments measured at NAV often provide for daily, monthly, or quarterly redemptions with 60 or less days of notice depending on the fund. For some funds, redemption may also require approval from the fund's board of directors. Derivative contracts are valued at fair value, as determined by the investment managers (or independent third parties on behalf of the investment managers), who use proprietary models and take into consideration exchange quotations on underlying instruments, dealer quotations, and other market information.

The following table sets forth, by level within the fair value hierarchy discussed in Note 8 – Fair Value Measurements, the pension plans' assets measured at fair value and NAV as of December 31, 2024 and 2023:

	December 31, 2024				December 31, 2023			
	Level 1	Level 2	NAV	Total	Level 1	Level 2	NAV	Total
Cash and cash equivalents	\$ —	\$ —	\$ 75	\$ 75	\$ —	\$ —	\$ 90	\$ 90
Equity securities:								
U.S. large-capitalization	—	—	689	689	—	—	663	663
U.S. small- and mid-capitalization	375	—	—	375	353	—	—	353
International	182	—	226	408	316	—	229	545
Global	—	—	680	680	—	—	721	721
Debt securities:								
Corporate bonds	—	463	—	463	—	479	—	479
Municipal bonds	—	36	—	36	—	43	—	43
U.S. Treasury and agency securities	—	1,032	—	1,032	—	994	—	994
Diversified credit	—	—	344	344	—	—	305	305
Other	(17)	11	—	(6)	49	13	—	62
Real estate	—	—	233	233	—	—	248	248
Total	\$ 540	\$ 1,542	\$ 2,247	\$ 4,329	\$ 718	\$ 1,529	\$ 2,256	\$ 4,503
Less: Medical benefit assets ^(a)				(200)				(196)
Plus: Net receivables (payables) ^(b)				53				(35)
Fair value of pension plans' assets				\$ 4,182				\$ 4,272

- (a) Medical benefit (health and welfare) component for accounts maintained in accordance with Section 401(h) of the Internal Revenue Code to fund a portion of the postretirement obligation.
(b) Net of receivables related to pending securities sales and payables related to pending securities purchases.

The following table sets forth, by level within the fair value hierarchy discussed in Note 8 – Fair Value Measurements, the postretirement benefit plans' assets measured at fair value and NAV as of December 31, 2024 and 2023:

	December 31, 2024				December 31, 2023			
	Level 1	Level 2	NAV	Total	Level 1	Level 2	NAV	Total
Cash and cash equivalents	\$ 25	\$ —	\$ —	\$ 25	\$ 10	\$ —	\$ —	\$ 10
Equity securities:								
U.S. large-capitalization	332	—	91	423	302	—	81	383
U.S. small- and mid-capitalization	106	—	—	106	96	—	—	96
International	54	—	52	106	51	—	49	100
Global	—	—	165	165	—	—	174	174
Debt securities:								
Municipal bonds	—	173	—	173	—	161	—	161
Other	—	—	293	293	—	—	271	271
Total	\$ 517	\$ 173	\$ 601	\$ 1,291	\$ 459	\$ 161	\$ 575	\$ 1,195
Plus: Medical benefit assets ^(a)				200				196
Plus: Net receivables ^(b)				2				2
Fair value of postretirement benefit plans' assets				\$ 1,493				\$ 1,393

- (a) Medical benefit (health and welfare) component for accounts maintained in accordance with Section 401(h) of the Internal Revenue Code to fund a portion of the postretirement obligation. These 401(h) assets are included in the pension plan assets shown above.
(b) Net of receivables related to pending securities sales and payables related to pending securities purchases.

Net Periodic Benefit Cost

The following table presents the components of the net periodic benefit cost (income) of Ameren's pension and postretirement benefit plans during 2024, 2023, and 2022:

	Pension Benefits			Postretirement Benefits		
	2024	2023	2022	2024	2023	2022
Service cost ^(a)	\$ 88	\$ 79	\$ 128	\$ 12	\$ 12	\$ 20
Non-service cost components:						
Interest cost	222	221	163	44	45	34
Expected return on plan assets ^(b)	(327)	(333)	(320)	(93)	(91)	(85)
Amortization of ^(c) :						
Prior service cost (credit)	—	—	—	(4)	(4)	(4)
Actuarial (gain) loss	(67)	(115)	25	(38)	(45)	(19)
Total non-service cost components^(c)	\$ (172)	\$ (227)	\$ (132)	\$ (91)	\$ (95)	\$ (74)
Net periodic benefit cost (income)^(d)	\$ (84)	\$ (148)	\$ (4)	\$ (79)	\$ (83)	\$ (54)

- (a) Service cost, net of capitalization, is reflected in "Operating Expenses - Other operations and maintenance" on Ameren's statement of income.
(b) Prior service cost (credit) is amortized on a straight-line basis over the average future service of active participants benefiting under the plan amendment. Net actuarial gains or losses related to the net benefit obligation subject to amortization are amortized on a straight-line basis over 10 years. The difference between the actual and expected return on plan assets is amortized over 4 years.
(c) Non-service cost components are reflected in "Other Income, Net" on Ameren's consolidated statement of income. See Note 6 – Other Income, Net for additional information.
(d) Does not include the impact of the tracker for the difference between the level of pension and postretirement benefit costs (income) incurred by Ameren Missouri under GAAP and the level of such costs included in rates.

The Ameren Companies are responsible for their share of the pension and postretirement benefit costs (income). The following table presents the pension and postretirement benefit costs (income) incurred for the years ended December 31, 2024, 2023, and 2022:

	Pension Costs			Postretirement Costs		
	2024	2023	2022	2024	2023	2022
Ameren Missouri ^(a)	\$ (44)	\$ (76)	\$ (3)	\$ (27)	\$ (30)	\$ (14)
Ameren Illinois	(34)	(62)	3	(52)	(54)	(41)
Other	(6)	(10)	(4)	—	1	1
Ameren	\$ (84)	\$ (148)	\$ (4)	\$ (79)	\$ (83)	\$ (54)

- (a) Does not include the impact of the tracker for the difference between the level of pension and postretirement benefit costs (income) incurred by Ameren Missouri under GAAP and the level of such costs included in customer rates.

The expected pension and postretirement benefit payments from qualified trust and company funds, which reflect expected future service, as of December 31, 2024, are as follows:

	Pension Benefits		Postretirement Benefits	
	Paid from Qualified Trust Funds	Paid from Company Funds	Paid from Qualified Trust Funds	Paid from Company Funds
2025	\$ 284	\$ 2	\$ 56	\$ 3
2026	289	2	57	3
2027	292	2	57	4
2028	295	2	57	4
2029	297	2	57	4
2030 – 2034	1,504	13	284	18

The following table presents the assumptions used to determine net periodic benefit cost for our pension and postretirement benefit plans for the years ended December 31, 2024, 2023, and 2022:

	Pension Benefits			Postretirement Benefits		
	2024	2023	2022	2024	2023	2022
Discount rate at measurement date	5.25 %	5.55 %	3.00 %	5.25 %	5.55 %	3.00 %
Expected return on plan assets	6.75	6.75	6.50	6.75	6.75	6.50
Increase in future compensation ^(a)	3.50	3.50	3.50	3.50	3.50	3.50
Cash balance pension plan interest crediting rate ^(b)	5.50	5.00	5.00	(c)	(c)	(c)
Medical cost trend rate (initial) ^(d)	(c)	(c)	(c)	(e)	(f)	5.00
Medical cost trend rate (ultimate) ^(d)	(c)	(c)	(c)	5.00	5.00	5.00

- (a) Increase in future compensation is 4.00% for 2024 and 3.50% thereafter for the year ended December 31, 2024, and was 4.50% for 2023, 4.00% for 2024, and 3.50% thereafter for the year ended December 31, 2023.
(b) Cash balance pension plan interest crediting rate is 6.42% for 2024 and 5.50% thereafter for the year ended December 31, 2024, and was 5.50% for 2023 and 2024, and 5.00% thereafter for the year ended December 31, 2023.
(c) Not applicable.
(d) Initial and ultimate medical cost trend rate for certain Medicare-eligible participants is 2.50% for the years ended December 31, 2024 and 2023, and 3.00% for the year ended December 31, 2022.
(e) Initial medical cost trend rates of 6.93% for pre-Medicare plan participants and 6.50% for post-Medicare plan participants trend down to the ultimate rate by 2030, with a 3.00% upward adjustment to the post-Medicare trend rate in 2025.
(f) Initial medical cost trend rates of 7.25% for pre-Medicare plan participants and 6.75% for post-Medicare plan participants trend down to the ultimate rate by 2030, with a 3.00% upward adjustment to the post-Medicare trend rate in 2025.

Other

Ameren sponsors a 401(k) plan for eligible employees. The Ameren 401(k) plan covered all eligible Ameren employees at December 31, 2024. The plan allows employees to contribute a portion of their compensation in accordance with specific guidelines. Ameren matches a percentage of the employee contributions up to certain limits. The following table presents the portion of the matching contribution to the Ameren 401(k) plan attributable to each of the Ameren Companies for the years ended December 31, 2024, 2023, and 2022:

	2024	2023	2022
Ameren Missouri	\$ 26	\$ 27	\$ 23
Ameren Illinois	22	21	19
Other	1	1	1
Ameren	\$ 49	\$ 49	\$ 43

NOTE 11 – STOCK-BASED COMPENSATION

The 2022 Omnibus Incentive Compensation Plan is Ameren's long-term incentive plan available for eligible employees and directors. It provides for a maximum of 8.8 million common shares to be available for grant to eligible employees and directors. At December 31, 2024, there were 7.7 million common shares remaining for grant. Awards may be restricted stock, restricted stock units, stock options (incentive stock options and nonqualified stock options), stock appreciation rights, performance awards, cash-based awards and other stock-based awards. Ameren used newly issued shares to fulfill its stock-based compensation obligations for 2024, 2023, and 2022, and intends to use newly issued shares to fulfill its stock-based compensation obligations for 2025.

The following table summarizes Ameren's outstanding performance share unit and restricted stock unit activity for the year ended December 31, 2024:

	Performance Share Units – Market Condition ^(a)		Performance Share Units – Performance Condition ^(b)		Restricted Stock Units	
	Share Units	Weighted-average Fair Value per Share Unit	Share Units	Weighted-average Fair Value per Share Unit	Stock Units	Weighted-average Fair Value per Stock Unit
Outstanding at January 1, 2024 ^(c)	761,712	\$ 89.22	112,391	\$ 83.36	377,864	\$ 83.82
Granted	314,456	56.73	51,938	68.83	159,050	69.09
Forfeitures	(46,636)	73.97	(7,691)	77.22	(29,330)	79.59
Dividend equivalents ^(d)	27,508	77.74	4,127	79.03	13,580	79.59
Vested and distributed	(248,090)	87.10	(39,768)	78.11	(125,644)	78.58
Outstanding at December 31, 2024 ^(c)	808,950	\$ 77.73	120,997	\$ 79.09	395,520	\$ 79.73

- (a) The exact number of shares issued pursuant to a share unit varies from 0% to 200% of the target award, depending on actual company performance relative to the specified market conditions. Compensation cost on nonforfeited awards is recognized regardless of whether Ameren achieves the specified market conditions.
(b) The exact number of shares issued pursuant to a share unit varies from 0% to 200% of the target award, depending on actual company performance relative to the performance goals. Compensation cost is recognized ratably over the requisite service period only for awards for which it is probable that the performance condition will be satisfied.
(c) Outstanding awards include awards that vest on a pro-rata basis due to attainment of retirement eligibility by employees, but have not yet been distributed. In these cases, the pro-rata basis awards have not yet been distributed as the entire performance period has not been completed. The number of shares issued for retirement-eligible employees will vary depending on actual performance over the three-year performance period.
(d) Dividend equivalents represent the right to receive shares measured by the dividend payable with respect to the corresponding number of outstanding share units. Dividend equivalents will accrue and be reinvested in additional share units throughout the performance period.

Performance Share Units – Market Condition

A market condition performance share unit vests and entitles an employee to receive shares of Ameren common stock (plus accumulated dividends) if, at the end of the three-year performance period, certain specified market conditions have been met and if the individual remains employed by Ameren through the required vesting period. The vesting period for share units awarded extends beyond the three-year performance period to the payout date, which is approximately 38 months after the grant date. In the event of a participant's death or retirement at age 55 or older with five years or more of service, awards vest on a pro-rata basis over the three-year performance period. The exact number of shares issued pursuant to a share unit varies from 0% to 200% of the target award, depending on actual company performance relative to the specified market conditions.

The fair value of each share unit is based on a Monte Carlo simulation. The Monte Carlo simulation is used to estimate expected share payout based on Ameren's TSR for a three-year performance period relative to the designated peer group beginning January 1st of the award year. The simulation can produce a greater or lesser fair value for the share unit than the applicable closing common share price because it includes the weighted payout scenarios in which an increase or decrease in the share price has occurred and/or in which the payout is above 100% due to Ameren's projected TSR performance. The key assumptions used to calculate fair value also include a three-year risk-free rate, Ameren's common stock volatility, and volatility for the peer group. The following table presents the fair value of each share unit along with the significant assumptions used to calculate the fair value of each share unit for the years ended December 31, 2024, 2023, and 2022:

	2024	2023	2022
Fair value of share units awarded	\$56.73	\$91.07	\$92.75
Three-year risk-free rate	4.25%	4.19%	1.80%
Ameren's common stock volatility ^(a)	21%	26%	29%
Volatility range for the peer group ^(a)	19% – 23%	24% – 32%	26% – 35%

- (a) Based on a historical period that is equal to the remaining term of the performance period as of the grant date.

In addition to the market condition performance share units described above, there are an immaterial number of market condition performance share units with different vesting conditions and target payout percentages.

Performance Share Units – Performance Condition

A performance condition share unit vests and entitles an employee to receive shares of Ameren common stock (plus accumulated dividends) if, at the end of the three-year performance period, Ameren has met the specified performance condition and if the individual remains employed by Ameren through the required vesting period. The vesting period for share units awarded extends beyond the three-year performance period to the payout date, which is approximately 38 months after the grant date. In the event of a participant's death or retirement at age 55 or older with five years or more of service, awards vest on a pro-rata basis over the three-year performance period. The exact number of shares issued pursuant to a share unit varies from 0% to 200% of the target award, depending on actual performance conditions achieved. The specified performance condition in each award year is based on Ameren's clean energy transition. The grant-date fair value for an individual outcome of a performance condition is determined by Ameren's closing common share price on the grant date.

Restricted Stock Units

Restricted stock units vest and entitle an employee to receive shares of Ameren common stock (plus accumulated dividends) if the individual remains employed with Ameren through the payment date of the awards. Generally, in the event of a participant's death or retirement at age 55 or older with five years or more of service, awards vest on a pro-rata basis. The payout date of the awards is approximately 38 months after the grant date. The fair value of each restricted stock unit is determined by Ameren's closing common share price on the grant date.

Stock-Based Compensation Expense

The following table presents the stock-based compensation expense for the years ended December 31, 2024, 2023, and 2022:

	2024	2023	2022
Ameren Missouri	\$ 8	\$ 6	\$ 4
Ameren Illinois	4	4	2
Other ^(a)	16	16	18
Ameren	28	26	24
Less: Income tax benefit	7	7	6
Stock-based compensation expense, net	\$ 21	\$ 19	\$ 18

(a) Represents compensation expense for employees of Ameren Services. These amounts are not included in the Ameren Missouri and Ameren Illinois amounts above.

Ameren settled performance share units and restricted stock units of \$24 million, \$60 million, and \$47 million for the years ended December 31, 2024, 2023, and 2022, respectively. There were no significant stock-based compensation costs capitalized during the years ended December 31, 2024, 2023, and 2022. As of December 31, 2024, total compensation cost of \$39 million related to outstanding awards not yet recognized is expected to be recognized over a weighted-average period of 23 months.

For the years ended December 31, 2024, 2023, and 2022, excess tax benefits (deficiencies) associated with the settlement of stock-based compensation awards reduced (increased) income tax expense by \$(1) million, \$6 million, and \$5 million, respectively.

NOTE 12 – INCOME TAXES

IRA

The IRA was enacted in August 2022, and includes various income tax provisions, among other things. The law extends federal production and investment tax credits for projects beginning construction through 2024 and allows for a 10% adder to the production and investment tax credits for siting projects at existing energy communities as defined in the law, which includes sites previously used for coal-fired generation. The law also creates clean energy tax credits for projects beginning construction after 2024. The clean energy tax credits will apply to renewable energy production and investments, along with certain nuclear energy production, and will be phased out beginning in 2033, at the earliest. The phase-out is triggered when greenhouse gas emissions from the electric generation industry are reduced by at least 75% from the annual 2022 emission rate or at the beginning of 2033, whichever is later. The law allows for transferability to an unrelated party for cash of up to 100% of certain tax credits generated after 2022. In addition, the law imposes a 15% minimum tax on adjusted financial statement income, as defined in the law, for corporations whose average annual adjusted financial statement income exceeds \$1 billion for three consecutive preceding tax years effective for tax years beginning after December 31, 2022. Once a corporation exceeds this three-year average annual adjusted financial statement income threshold, it will be subject to the minimum tax for all future tax years. Additional regulations, interpretations, amendments, or technical corrections to or in connection with the IRA have been and are expected to be issued by the IRS or United States Department of Treasury, which may impact the timing of when the 15% minimum tax becomes applicable for Ameren.

IRS Natural Gas Repairs and Maintenance Guidance

In April 2023, the IRS issued guidance providing a safe harbor method of accounting for the capitalization or deduction of certain expenditures to maintain, repair, replace, or improve natural gas distribution and transmission property. Ameren adopted this guidance for the 2024 tax year and, as a result, during December 2024, Ameren, Ameren Missouri, and Ameren Illinois recorded increases to their "plant-related" deferred tax liabilities of \$123 million, \$12 million, and \$111 million, respectively.

The following table presents the principal reasons for the difference between the effective income tax rate and the federal statutory corporate income tax rate for the years ended December 31, 2024, 2023, and 2022:

	Ameren Missouri	Ameren Illinois	Ameren
2024			
Federal statutory corporate income tax rate	21 %	21 %	21 %
Increases (decreases) from:			
Amortization of excess deferred income taxes ^(a)	(17)	(4)	(9)
Amortization of deferred investment tax credit	(1)	—	—
Renewable and other tax credits ^(b)	(24)	—	(9)
State tax	3	7	5
Depreciation differences	—	—	(1)
Effective income tax rate	(18)%	24 %	7 %
2023			
Federal statutory corporate income tax rate	21 %	21 %	21 %
Increases (decreases) from:			
Amortization of excess deferred income taxes ^(a)	(15)	(2)	(8)
Amortization of deferred investment tax credit	(1)	—	—
Renewable and other tax credits ^(b)	(10)	—	(4)
State tax	3	7	5
Effective income tax rate	(2)%	26 %	14 %
2022			
Federal statutory corporate income tax rate	21 %	21 %	21 %
Increases (decreases) from:			
Amortization of excess deferred income taxes ^(a)	(15)	(2)	(8)
Amortization of deferred investment tax credit	(1)	—	—
Renewable and other tax credits ^(b)	(10)	—	(4)
State tax	3	7	5
Effective income tax rate	(2)%	26 %	14 %

(a) Reflects the amortization of a regulatory liability resulting from the revaluation of accumulated deferred income taxes subject to regulatory ratemaking, which are being refunded to customers.

(b) The benefit of the credits associated with Missouri renewable energy standard compliance is refunded to customers through the RESRAM. The benefit of the credits associated with the production and investment tax credit tracker will be refunded to customers based on MoPSC approval in a regulatory rate review.

The following table presents the components of income tax expense (benefit) for the years ended December 31, 2024, 2023, and 2022:

	Ameren Missouri	Ameren Illinois	Other	Ameren
2024				
Current taxes:				
Federal	\$ (55)	\$ 5	\$ 7	(43)
State	(3)	—	2	(1)
Deferred taxes:				
Federal	45	144	(12)	177
State	8	76	(19)	65
Amortization of excess deferred income taxes	(79)	(32)	(1)	(112)
Amortization of deferred investment tax credits	(3)	—	—	(3)
Total income tax expense (benefit)	\$ (87)	\$ 193	\$ (23)	\$ 83
2023				
Current taxes:				
Federal	\$ (37)	\$ 27	\$ (37)	(47)
State	1	5	(5)	1
Deferred taxes:				
Federal	102	123	35	260
State	9	71	(10)	70
Amortization of excess deferred income taxes	(80)	(17)	(1)	(98)
Amortization of deferred investment tax credits	(3)	—	—	(3)
Total income tax expense (benefit)	\$ (8)	\$ 209	\$ (18)	\$ 183
2022				
Current taxes:				
Federal	\$ (26)	\$ 46	\$ (15)	5
State	(5)	16	(10)	1
Deferred taxes:				
Federal	93	82	19	194
State	18	48	14	80
Amortization of excess deferred income taxes	(86)	(13)	(1)	(100)
Amortization of deferred investment tax credits	(4)	—	—	(4)
Total income tax expense (benefit)	\$ (10)	\$ 179	\$ 7	\$ 176

The following table presents the accumulated deferred income tax assets and liabilities recorded for GAAP purposes as a result of temporary differences and accumulated deferred production and investment tax credits at December 31, 2024 and 2023:

	Ameren Missouri	Ameren Illinois	Other	Ameren
2024				
Accumulated deferred income taxes, net liability (asset):				
Plant-related	\$ 2,429	\$ 2,250	\$ 261	4,940
Regulatory assets and liabilities, net	(193)	(170)	(22)	(385)
Deferred employee benefit costs	(25)	77	(25)	27
Tax carryforwards	(355)	(45)	(103)	(503)
Other	131	28	3	162
Total net accumulated deferred income tax liabilities (assets)	1,987	2,140	114	4,241
Accumulated deferred investment tax credits	230	3	—	233
Accumulated deferred income taxes and investment tax credits	\$ 2,217	\$ 2,143	\$ 114	\$ 4,474
2023				
Accumulated deferred income taxes, net liability (asset):				
Plant-related	\$ 2,370	\$ 2,030	\$ 246	4,646
Regulatory assets and liabilities, net	(206)	(184)	(23)	(413)
Deferred employee benefit costs	(48)	55	(33)	(26)
Tax carryforwards	(124)	(33)	(61)	(218)
Other	104	38	19	161
Total net accumulated deferred income tax liabilities (assets)	2,096	1,906	148	4,150
Accumulated deferred investment tax credits	26	—	—	26
Accumulated deferred income taxes and investment tax credits	\$ 2,122	\$ 1,906	\$ 148	\$ 4,176

The following table presents the components of accumulated deferred income tax assets relating to net operating loss carryforwards and tax credit carryforwards at December 31, 2024 and 2023:

	Ameren Missouri	Ameren Illinois	Other	Ameren
2024				
Net operating loss carryforwards:				
Federal ^(a)	\$ —	\$ —	\$ 30	30
State ^(b)	—	34	29	63
Total net operating loss carryforwards	\$ —	\$ 34	\$ 59	\$ 93
Tax credit carryforwards:				
Federal ^(c)	\$ 355	\$ 9	\$ 44	408
State ^(d)	—	2	—	2
Total tax credit carryforwards	\$ 355	\$ 11	\$ 44	\$ 410
2023				
Net operating loss carryforwards:				
Federal	\$ —	\$ —	\$ —	—
State	—	26	16	42
Total net operating loss carryforwards	\$ —	\$ 26	\$ 16	\$ 42
Tax credit carryforwards:				
Federal	\$ 124	\$ 5	\$ 45	174
State	—	2	—	2
Total tax credit carryforwards	\$ 124	\$ 7	\$ 45	\$ 176

- (a) No expiration date.
(b) Will expire between 2032 and 2044.
(c) Will expire between 2031 and 2044.
(d) Will expire between 2025 and 2028.

Uncertain Tax Positions

As of December 31, 2024 and 2023, the Ameren Companies did not record any uncertain tax positions.

Ameren is a part of the IRS's compliance assurance process program, which involves real-time review of compliance with federal income tax law. State income tax returns are generally subject to examination for a period of three years after filing. The state impact of any federal changes remains subject to examination by various states for up to one year after formal notification to the states. Ameren's federal tax return for the 2023 tax year is open, but, at the time of this filing, the Ameren Companies do not have material income tax issues under examination, administrative appeals, or litigation.

NOTE 13 – RELATED-PARTY TRANSACTIONS

In the normal course of business, Ameren Missouri and Ameren Illinois engage in affiliate transactions. These transactions primarily consist of natural gas and power purchases and sales, services received or rendered, and borrowings and lendings. Transactions between Ameren's subsidiaries are reported as affiliate transactions on their individual financial statements, but those transactions are eliminated in consolidation for Ameren's consolidated financial statements. Below are the material related-party agreements.

Electric Power Supply Agreements

Ameren Illinois must acquire capacity and energy sufficient to meet its obligations to customers. Ameren Illinois uses periodic RFP processes, administered by the IPA and approved by the ICC, to contract capacity and energy on behalf of its customers. Ameren Missouri participates in the RFP process and has been a winning supplier for certain periods.

Capacity Supply Agreements

In procurement events in 2021, Ameren Missouri contracted to supply a portion of Ameren Illinois' capacity requirements for \$2 million from June 2022 through May 2023.

Energy Product Agreements

Based on the outcome of IPA-administered procurement events, Ameren Missouri and Ameren Illinois have entered into energy product agreements by which Ameren Missouri agreed to sell, and Ameren Illinois agreed to purchase, a set amount of MWhs at a predetermined price over a specified period of time. The following table presents the specified performance period, amount of MWhs, and average price per MWh included in the agreements:

IPA Procurement Event	Performance Period	MWhs	Average Price per MWh
September 2020	September 2021 – November 2022	204,800	31
April 2021	July 2022 – November 2022	33,600	34
September 2021	January 2022 – September 2023	136,000	37

Interconnection Agreements

Ameren Missouri and Ameren Illinois are parties to an interconnection agreement that governs the connection of their respective transmission lines and other facilities used for the distribution of power. These agreements have no contractual expiration date, but may be terminated by either party with three years' notice.

Ameren Missouri and ATXI are parties to an interconnection agreement that governs the connection of the High Prairie Energy Center to an ATXI transmission line that allows Ameren Missouri to distribute power generated from the High Prairie Energy Center.

Ameren Missouri and Ameren Illinois are parties to interconnection agreements that govern the connection of the Cass County and Boomtown energy centers to Ameren Illinois transmission lines that allows Ameren Missouri to distribute power generated from the Cass County and Boomtown energy centers.

Support Services Agreements

Ameren Services provides support services to its affiliates. The costs of support services including wages, employee benefits, professional services, and other expenses, are based on, or are an allocation of, actual costs incurred. The support services agreement can be terminated at any time by the mutual agreement of Ameren Services and that affiliate or by either party with 60 days' notice before the end of a calendar year.

In addition, Ameren Missouri and Ameren Illinois provide affiliates with access to their facilities for administrative purposes and with use of other assets. The costs of the rent and facility services and other assets are based on, or are an allocation of, actual costs incurred.

Ameren Missouri and Ameren Illinois also provide storm-related and miscellaneous support services to each other on an as-needed basis.

Ameren Missouri and Ameren Illinois had long-term receivables included in "Other assets" from Ameren Services of \$29 million and \$32 million, respectively, as of December 31, 2024, and \$31 million and \$34 million, respectively, as of December 31, 2023, related to Ameren Services' allocated portion of Ameren's pension and postretirement benefit plans.

Transmission Services

Ameren Missouri and Ameren Illinois each receives transmission services from ATXI for their respective retail loads.

Electric Transmission Maintenance and Construction Agreements

ATXI entered into separate agreements with Ameren Missouri and Ameren Illinois in which Ameren Missouri or Ameren Illinois, as applicable, may perform certain maintenance and construction services related to ATXI's electric transmission assets.

Money Pool

See Note 4 – Short-term Debt and Liquidity for a discussion of affiliate borrowing arrangements.

Long-Term Debt, Net - Related Parties

In November and December 2024, Ameren (parent) purchased senior secured notes and first mortgage bonds issued by Ameren Missouri, and first mortgage bonds issued by Ameren Illinois. See Note 5 – Long-term Debt and Equity Financings for additional information.

Tax Allocation Agreement

See Note 1 – Summary of Significant Accounting Policies for a discussion of the tax allocation agreement. The following table presents the affiliate balances related to income taxes for Ameren Missouri and Ameren Illinois as of December 31, 2024 and 2023:

	2024		2023	
	Ameren Missouri	Ameren Illinois	Ameren Missouri	Ameren Illinois
Income taxes payable to parent ^(a)	\$ —	\$ 32	\$ —	\$ 2
Income taxes receivable from parent ^(b)	28	—	56	22

(a) Included in "Accounts payable – affiliates" on the balance sheet.

(b) Included in "Accounts receivable – affiliates" on the balance sheet.

Capital Contributions

The following table presents cash capital contributions received from Ameren (parent) by Ameren Missouri and Ameren Illinois for the years ended December 31, 2024, 2023, and 2022:

	2024	2023	2022
Ameren Missouri ^(a)	\$ 476	\$ —	\$ —
Ameren Illinois ^(a)	36	91	15

(a) Includes capital contributions made as a result of the tax allocation agreement.

Effects of Related-party Transactions on the Statement of Income

The following table presents the impact on Ameren Missouri and Ameren Illinois of related-party transactions for the years ended December 31, 2024, 2023, and 2022. It is based primarily on the agreements discussed above and the money pool arrangements discussed in Note 4 – Short-term Debt and Liquidity.

Agreement	Income Statement Line Item		Ameren Missouri	Ameren Illinois
Ameren Missouri power supply agreements with Ameren Illinois	Operating Revenues	2024	\$ —	(a)
		2023	2	(a)
		2022	9	(a)
Ameren Missouri and Ameren Illinois rent and facility services	Operating Revenues	2024	31	1
		2023	32	(b)
		2022	25	(b)
Ameren Missouri and Ameren Illinois miscellaneous support services	Operating Revenues	2024	2	2
		2023	(b)	2
		2022	(b)	2
Total Operating Revenues		2024	\$ 33	\$ 3
		2023	34	2
		2022	34	2
Ameren Illinois power supply agreements with Ameren Missouri	Purchased Power	2024	(a)	—
		2023	(a)	2
		2022	(a)	9
Ameren Missouri and Ameren Illinois transmission services from ATXI	Purchased Power	2024	9	2
		2023	2	1
		2022	1	(b)
Total Purchased Power		2024	\$ 9	\$ 2
		2023	2	3
		2022	1	9
Ameren Missouri and Ameren Illinois rent and facility services	Other Operations and Maintenance	2024	\$ 1	\$ 1
		2023	(b)	3
		2022	(b)	3
Ameren Services support services agreement	Other Operations and Maintenance	2024	169	158
		2023	148	138
		2022	150	141
Total Other Operations and Maintenance Expenses		2024	\$ 170	\$ 159
		2023	148	141
		2022	150	144
Money pool borrowings (advances)	(Interest Charges)	2024	\$ (4)	(b)
		2023	(b)	(b)
		2022	(b)	(b)
Long-term debt, net - related parties	(Interest Charges)	2024	(b)	(b)
		2023	(a)	(a)
		2022	(a)	(a)

(a) Not applicable.

(b) Amount less than \$1 million.

NOTE 14 – COMMITMENTS AND CONTINGENCIES

We are involved in legal, tax, and regulatory proceedings before various courts, regulatory commissions, authorities, and governmental agencies with respect to matters that arise in the ordinary course of business, some of which involve substantial amounts of money. We believe that the final disposition of these proceedings, except as otherwise disclosed in the notes to our financial statements, will not have a material adverse effect on our results of operations, financial position, or liquidity.

See also Note 1 – Summary of Significant Accounting Policies, Note 2 – Rate and Regulatory Matters, Note 9 – Callaway Energy Center, Note 13 – Related-party Transactions, and Note 15 – Supplemental Information in this report.

Environmental Matters

Our electric generation, transmission, and distribution and natural gas distribution and storage operations must comply with a variety of statutes and regulations relating to the protection of the environment and human health and safety, including permitting programs implemented by federal, state, and local authorities. Such environmental laws regulate air emissions; protect water bodies; manage the handling and disposal of hazardous substances and waste materials; siting and land use requirements; and potential ecological impacts. Complex and lengthy processes are required to obtain and renew approvals, permits, and licenses for new, existing, or modified energy-related facilities. Additionally, the use and handling of various chemicals or hazardous materials require release prevention plans and emergency response procedures.

Environmental regulations have a significant impact on the electric utility industry and compliance with these regulations could be costly for Ameren Missouri, which operates coal-fired and natural gas-fired energy centers. Compliance obligations under the Clean Air Act include the NSPS, the MATS, emission allowance programs and the CSAPR, and the National Ambient Air Quality Standards, which are subject to periodic review for certain pollutants. Collectively, these regulations cover a variety of pollutants, such as SO₂, particulate matter, NO_x, mercury, toxic metals and acid gases, and CO₂ emissions. Regulations implementing the Clean Water Act govern potential impacts from our operations on water bodies including wetlands subject to the Act, as well as evaluation of the ecological and biological impact of those operations. Implementation of the Clean Air Act and the Clean Water Act requirements typically occurs through the issuance of permits by state regulators or resource agencies, and capital expenditures associated with compliance could be significant. Coal-fired energy centers must comply with management and disposal requirements for coal ash under the Resource Conservation and Recovery Act and federal regulations known as the CCR Rule. Surface impoundments at Ameren Missouri's coal-fired energy centers are subject to closure and groundwater monitoring requirements and the implementations of corrective measures if necessary. The individual or combined effects of compliance with existing and new environmental regulations could result in significant capital expenditures, increased operating costs, or the closure or alteration of operations at some of Ameren Missouri's energy centers. Ameren and Ameren Missouri expect that such compliance costs would be recoverable through rates, subject to MoPSC prudence review, but the timing of costs and their recovery could be subject to regulatory lag.

Additionally, Ameren Missouri's wind generation facilities may be subject to operating restrictions to limit the impact on protected species. Since 2021, Ameren Missouri's High Prairie Energy Center curtailed nighttime operations from April through October to limit impacts on protected species during the critical biological season. The extent and duration of future curtailments are currently unknown as assessment of mitigation technologies is ongoing. In Ameren Missouri's 2024 electric service regulatory rate review, the MoPSC staff and the MoOPC have recommended reductions to the revenue requirement associated with the nighttime curtailment of the High Prairie Energy Center. See Note 2 – Rate and Regulatory Matters for additional information.

Ameren and Ameren Missouri estimate that they may need to make capital expenditures of \$900 million to \$1 billion from 2025 through 2029 to comply with environmental regulations. Additional capital expenditures for environmental controls beyond 2029 could be required. These estimates include capital expenditures that may be necessary to comply with regulations issued by the EPA in 2024

relating to CO₂ emissions and MATS discussed below, assuming these regulations are not revised or overturned. This estimate of capital expenditures also includes surface impoundment closure and corrective action measures required by the 2015 CCR Rule and modifications to cooling water intake structures at existing power plants under Clean Water Act rules in place prior to 2024, all of which are discussed below. Congress and the EPA could review and revise compliance requirements. In addition to planned retirements of coal-fired energy centers that will be included in Ameren Missouri's 2025 Change to the 2023 PRP and as noted below with respect to the NSR and Clean Air Act litigation and Illinois emissions standards, Ameren Missouri's current plan for compliance with existing air emission regulations includes burning low-sulfur coal and installing new or optimizing existing air pollution control equipment. Accordingly, the actual amount of capital expenditures required to comply with existing environmental regulations may vary substantially from the above estimates because of uncertainty as to future permitting requirements by state regulators and the EPA, revisions to regulatory obligations, and varying cost of potential compliance strategies, among other things.

The following sections describe the significant environmental statutes and regulations and environmental enforcement and remediation matters that affect or could affect our operations. The EPA periodically amends and revises its regulations and proposes amendments to regulations and guidelines, which could ultimately result in the revision of all or part of such regulations.

Clean Air Act

Federal and state laws, including the CSAPR, regulate emissions of SO₂ and NO_x through the reduction of emissions at their source and the use and retirement of emission allowances. In April 2022, the EPA proposed the Good Neighbor Rule of the Clean Air Act, which includes additional NO_x emission reductions from power plants in Missouri, Illinois, and other states through revisions to the CSAPR. In January 2023, the EPA issued its final disapproval of Missouri's proposed state implementation plan for addressing the transport of ozone under the Good Neighbor Rule of the Clean Air Act. The disapproval of the state plan allowed the EPA to implement revisions to the CSAPR through a federal implementation plan that reduced the amount of NO_x allowances available for state budgets and imposed NO_x emission limits on electric generating units for Missouri, Illinois, and other states under the Good Neighbor Rule of the Clean Air Act. In April 2023, the Missouri Attorney General and Ameren Missouri separately filed lawsuits in the United States Court of Appeals for the Eighth Circuit challenging the EPA's disapproval of the Missouri state plan. Ameren expected a decision on Missouri's proposed state implementation plan under the Good Neighbor Rule by the United States Court of Appeals for the Eighth Circuit in 2025, but, in February 2025, the EPA requested that the appellate court suspend the case indefinitely and indicated it was reviewing the basis for the disapproval of the state implementation plans, including Missouri's. Ameren Missouri complies with the current CSAPR requirements by minimizing emissions through the use of low-sulfur coal, operation of two scrubbers at its Sioux Energy Center, and optimization of existing NO_x air pollution control equipment. Reducing the amount of state budget NO_x allowances for compliance with NO_x emission limits under the Good Neighbor Rule could result in additional controls being required on Ameren Missouri's generating units and/or the reduction of operations. Any costs for compliance are expected to be recovered from customers, subject to MoPSC prudence review, through the FAC or higher base rates.

CO₂ Emissions Standards

In April 2024, the EPA issued a final rule that sets CO₂ emission standards for existing coal-fired and new natural gas-fired power plants based on the emissions expected from adoption of carbon capture technology and/or natural gas co-firing for coal-fired power plants and carbon capture technology for new natural gas-fired power plants. Affected power plants are required to comply with the rule through a phased-in approach or retire. Compliance with the new rule could be required as early as 2030 for certain existing coal-fired power plants and 2032 for certain new natural gas-fired power plants. In December 2024, the United States Court of Appeals for the District of Columbia Circuit heard arguments from various stakeholders including the EPA, environmental organizations, state attorney generals, and industry groups regarding the legal merits of the final rule. In February 2025, the EPA requested that the appellate court suspend the case for 60 days and not issue an opinion so the EPA can decide how to proceed. Ameren and Ameren Missouri estimate capital expenditures of approximately \$580 million may be necessary to comply with the final rule assuming it is not revised or overturned. Ameren and Ameren Missouri are monitoring the legal challenges and assessing the impacts of the final rule and, at this time, cannot predict the final impacts on their results of operations, financial position, and liquidity.

MATS

In April 2024, the EPA revised the MATS by establishing a more stringent standard for emissions of particulate matter, as well as requiring the use of continuous emissions monitoring systems. Compliance with the revised rule is required by July 2027, with a possible one-year extension if certain conditions are met. Requests for a stay of the revised rule have been denied by the United States Court of Appeals for the District of Columbia Circuit and the United States Supreme Court. Arguments regarding the legal merits of the revised rule will be considered by the United States Court of Appeals for the District of Columbia Circuit. Ameren and Ameren Missouri estimate capital expenditures of approximately \$320 million may be necessary to comply with the final rule assuming it is not revised or overturned. Ameren and Ameren Missouri are monitoring the legal challenges and, at this time, cannot predict the final impacts on their results of operations, financial position, and liquidity.

NSPS

In November 2024, the EPA issued a proposed rule revising the NSPS to limit emissions of NO_x from natural gas-fired stationary CTs. If adopted as proposed, the rule would require such natural gas facilities which began construction after December 13, 2024, to install certain pollution control equipment to limit emissions of NO_x. In addition, the EPA proposed to maintain the current limits for SO₂ at such natural gas facilities. Ameren and Ameren Missouri cannot predict the potential impacts of any such rule on their results of operations, financial position, and liquidity until a final rule is adopted.

NSR and Clean Air Act Litigation

In January 2011, the United States Department of Justice, on behalf of the EPA, filed a complaint against Ameren Missouri in the United States District Court for the Eastern District of Missouri alleging that projects performed in 2007 and 2010 at the coal-fired Rush Island Energy Center violated provisions of the Clean Air Act and Missouri law. In January 2017, the district court issued a liability ruling against Ameren Missouri and, in September 2019, entered a remedy order that required Ameren Missouri to install a flue gas desulfurization system at the Rush Island Energy Center. In September 2023, the district court modified the remedy order to allow the early retirement of the Rush Island Energy Center in lieu of installing a flue gas desulfurization system. Ameren Missouri retired the Rush Island Energy Center on October 15, 2024. In December 2024, the United States District Court for the Eastern District of Missouri issued an order resolving all outstanding claims in this case. The order requires Ameren Missouri to fund a program to provide electric buses and charging stations to schools in the metro St. Louis area and a program to provide air purifiers to eligible Ameren Missouri electric residential customers. These programs are estimated to cost approximately \$64 million. As of December 31, 2024, Ameren and Ameren Missouri each recorded liabilities of \$40 million and \$24 million in "Other current liabilities" and "Other deferred credits and liabilities", respectively, on their consolidated balance sheets and recorded charges of \$59 million in "Other operations and maintenance" on their consolidated statements of income in 2024 related to the cost of these programs.

In connection with the accelerated retirement of the Rush Island Energy Center, the MoPSC issued an order in June 2024 authorizing Ameren Missouri to finance the costs associated with the retirement, including the remaining unrecovered net plant balance associated with the facility, through the issuance of securitized utility tariff bonds pursuant to Missouri's securitization statute. Costs associated with the retirement exclude any additional mitigation relief ordered in the NSR and Clean Air Act litigation discussed above. The securitized tariff bonds were issued in December 2024. See Note 2 – Rate and Regulatory Matters for additional information.

Clean Water Act

Among other items, the Clean Water Act requires power plant operators to evaluate cooling water intake structures and identify measures for reducing the number of aquatic organisms impinged on a power plant's cooling water intake screens or entrained through the plant's cooling water system. All of Ameren Missouri's coal-fired and nuclear energy centers are subject to this cooling water intake structures rule. Requirements of the rule are implemented by state regulators through the permit renewal process of each power plant's water discharge permit. Permits for Ameren Missouri's coal-fired and nuclear energy centers have been issued or are in the process of renewal.

In April 2024, the EPA issued new effluent limitation guidelines that established a zero discharge limit for flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate. Ameren and Ameren Missouri expect the impacts of the new guidelines on their results of operations, financial position, and liquidity to be immaterial.

CCR Management

The EPA's 2015 CCR Rule establishes requirements for the management and disposal of CCR from coal-fired power plants and has resulted in the closure of surface impoundments at Ameren Missouri's energy centers, with closures of surface impoundments in process at its Sioux Energy Center and retired Meramec Energy Center. Ameren Missouri plans to substantially complete the closures of remaining surface impoundments by the end of 2026. Ameren Missouri's CCR management compliance plan includes installation of groundwater monitoring equipment and groundwater treatment facilities. In April 2024, the EPA revised the CCR Rule to impose groundwater monitoring, and corrective action, closure, and post-closure requirements on certain active and inactive CCR surface impoundments and disposal units not previously included in the 2015 CCR Rule. Ameren and Ameren Missouri have AROs of \$46 million associated with CCR storage facilities recorded on their respective balance sheets as of December 31, 2024. This amount includes an immaterial incremental ARO related to the 2024 CCR Rule, which may be revised as additional site studies are performed. Ameren and Ameren Missouri are assessing the impacts of this rule revision and, at this time, cannot predict the final impacts on their results of operations, financial position, and liquidity.

Remediation

The Ameren Companies are involved in a number of remediation actions to clean up sites impacted by the use or disposal of materials containing hazardous substances. Federal and state laws can require responsible parties to fund remediation regardless of their degree of fault, the legality of original disposal, or the ownership of a disposal site.

As of December 31, 2024, Ameren Illinois has remediated the majority of the 44 former MGP sites in Illinois with an estimated remaining obligation primarily related to three of these former MGP sites at \$44 million to \$91 million. Ameren and Ameren Illinois recorded a liability of \$44 million to represent the estimated minimum obligation for these sites, as no other amount within the range was a better estimate. Ameren cannot estimate the completion date of the estimated remaining obligation due to site accessibility, among other things. The scope of the remediation activities at these former MGP sites may increase as remediation efforts continue. Considerable uncertainty remains in these estimates because many site-specific factors can influence the actual costs, including unanticipated underground structures, the degree to which groundwater is impacted, regulatory changes, local ordinances, and site accessibility. The actual costs and timing of completion may vary substantially from these estimates.

The ICC allows Ameren Illinois to recover MGP remediation and related litigation costs from its electric and natural gas utility customers through environmental cost riders that are subject to annual prudence reviews by the ICC.

Our operations or those of our predecessor companies involve the use of, disposal of, and, in appropriate circumstances, the cleanup of substances regulated under environmental laws. We are unable to determine whether such historical practices will result in future environmental commitments, including additional or more stringent cleanup standards, or will affect our results of operations, financial position, or liquidity.

Illinois Emission Standards

Currently as required by the CEJA, Ameren Missouri's natural gas-fired energy centers in Illinois are subject to annual limits on emissions, including CO₂ and NO_x. Further reductions to emissions limits will become effective between 2030 and 2040, resulting in the closure of the Venice Energy Center by the end of 2029. The reductions could also limit the operations of Ameren Missouri's four other natural gas-fired energy centers located in the state of Illinois, and will result in their closure by 2040. These energy centers are utilized to support peak loads. Subject to conditions in the CEJA, these energy centers may be allowed to exceed the emissions limits in order to maintain reliability of electric utility service.

NOTE 15 – SUPPLEMENTAL INFORMATION

Cash, Cash Equivalents, and Restricted Cash

The following table provides a GAAP reconciliation of cash, cash equivalents, and restricted cash reported within the balance sheets and the statements of cash flows as of December 31, 2024 and 2023:

	December 31, 2024			December 31, 2023		
	Ameren	Ameren Missouri	Ameren Illinois	Ameren	Ameren Missouri	Ameren Illinois
"Cash and cash equivalents"	\$ 7	\$ —	\$ —	\$ 25	\$ —	\$ —
Restricted cash included in "Other current assets"	15	7	6	13	5	5
Restricted cash included in "Other assets"	296	—	296	229	—	229
Restricted cash included in "Nuclear decommissioning trust fund"	10	10	—	5	5	—
Total cash, cash equivalents, and restricted cash	\$ 328	\$ 17	\$ 302	\$ 272	\$ 10	\$ 234

Restricted cash included in "Other current assets" represents funds held by an irrevocable Voluntary Employee Beneficiary Association (VEBA) trust, which provides health care benefits for active employees on Ameren's, Ameren Missouri's, and Ameren Illinois' balance sheets and AMF's restricted cash for payments for securitized utility tariff bonds on Ameren's and Ameren Missouri's balance sheets. Restricted cash included in "Other assets" on Ameren's and Ameren Illinois' balance sheets primarily represents amounts collected under a cost recovery rider restricted for use in the procurement of renewable energy credits and amounts in a trust fund restricted for the use of funding certain asbestos-related claims.

Accounts Receivable

"Accounts receivable – trade" on Ameren's and Ameren Illinois' balance sheets include certain receivables purchased at a discount from alternative retail electric suppliers that elect to participate in the utility consolidated billing program. At December 31, 2024 and 2023, "Other current liabilities" on Ameren's and Ameren Illinois' balance sheets included payables for purchased receivables of \$43 million and \$42 million, respectively.

The following table provides a reconciliation of the beginning and ending amount of the allowance for doubtful accounts for the years ended December 31, 2024 and 2023:

	December 31, 2024			December 31, 2023		
	Ameren Missouri	Ameren Illinois ^(a)	Ameren	Ameren Missouri	Ameren Illinois ^(a)	Ameren
Beginning balance at January 1	\$12	\$18	\$30	\$13	\$18	\$31
Bad debt expense	11	28	39	11	40	51
Charged to other accounts ^(b)	—	8	8	—	5	5
Net write-offs	(11)	(36)	(47)	(12)	(45)	(57)
Ending balance at December 31	\$12	\$18	\$30	\$12	\$18	\$30

(a) Ameren Illinois has rate-adjustment mechanisms that allow it to recover the difference between its actual net bad debt write-offs under GAAP, including those associated with receivables purchased from alternative retail electric suppliers, and the amount of net bad debt write-offs included in its base rates.

(b) Amounts associated with the allowance for doubtful accounts related to receivables purchased by Ameren Illinois from alternative retail electric suppliers, as required by the Illinois Public Utilities Act.

Leases

Ameren and Ameren Missouri have lease agreements primarily relating to rail cars and land related to solar generation facilities. The land leases are related to the Cass County, Boomtown, and Huck Finn energy centers. See Note 2 – Rate and Regulatory Matters for additional information on the acquisitions. Rail cars are leased for the transportation of coal to its energy centers. For rail car leases, we account for the lease and non-lease components as a single lease component, and for the land leases related to solar generation projects, we account for the components separately for each agreement. Certain of the land leases related to the acquisitions of the Cass County, Boomtown, and Huck Finn energy centers have options to renew or terminate those leases. Termination and renewal options are not expected to be exercised and are not included in any of the lease measurements used to record the leased assets and liabilities in the tables below.

The following table provides supplemental balance sheet information related to operating leases as of December 31, 2024:

	Ameren	Ameren Missouri
Other assets	\$ 72	\$ 69
Other current liabilities	5	4
Other deferred credits and liabilities	67	65
Weighted average remaining operating lease term	29 years	30 years
Weighted average discount rate ^(a)	5.3 %	5.3 %

(a) As an implicit rate is not readily determinable under most of our lease agreements, we use our incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. We use an implicit rate when readily determinable.

The following table presents Ameren's and Ameren Missouri's remaining maturities of operating lease liabilities as of December 31, 2024:

	Ameren		Ameren Missouri	
2025	\$	8	\$	7
2026		5		4
2027		4		3
2028		4		4
2029		4		4
Thereafter		131		131
Total lease payments	\$	156	\$	153
Less imputed interest		84		84
Total	\$	72	\$	69

Inventories

The following table presents the components of inventories for each of the Ameren Companies at December 31, 2024 and 2023:

	December 31, 2024			December 31, 2023		
	Ameren Missouri	Ameren Illinois	Ameren	Ameren Missouri	Ameren Illinois	Ameren
Fuel ^(a)	\$ 113	\$ —	\$ 113	\$ 109	\$ —	\$ 109
Natural gas stored underground	9	82	91	8	87	95
Materials, supplies, and other	392	162	558	391	138	529
Total inventories	\$ 514	\$ 244	\$ 762	\$ 508	\$ 225	\$ 733

(a) Consists of coal, oil, and propane.

Asset Retirement Obligations

The following table provides a reconciliation of the beginning and ending carrying amount of AROs for the years ended December 31, 2024 and 2023:

	December 31, 2024			December 31, 2023		
	Ameren Missouri	Ameren Illinois	Ameren	Ameren Missouri	Ameren Illinois	Ameren
Beginning balance at January 1	\$ 787 ^(a)	\$ 4 ^(b)	\$ 791 ^(a)	\$ 782	\$ 4	\$ 786
Liabilities incurred	21 ^(c)	—	21 ^(c)	—	—	—
Liabilities settled	(13)	—	(13)	(10)	—	(10)
Accretion ^(d)	35 ^(d)	—	35 ^(d)	33	—	33
Change in estimates	(7)	—	(7)	(18)	—	(18)
Ending balance at December 31	\$ 823 ^{(a)(e)}	\$ 4 ^(b)	\$ 827 ^{(a)(e)}	\$ 787 ^(a)	\$ 4 ^(b)	\$ 791 ^(a)

(a) Balance included \$5 million and \$19 million in "Other current liabilities" on the balance sheet as of December 31, 2024 and 2023, respectively.

(b) Included in "Other deferred credits and liabilities" on the balance sheet.

(c) In 2024, Ameren and Ameren Missouri recorded an ARO related to decommissioning for the Cass County, Boomtown, and Huck Finn energy centers. In addition, as a result of the 2024 CCR Rule, Ameren and Ameren Missouri recorded an increase to their AROs associated with CCR storage facilities. See Note 14 – Commitments and Contingencies for additional information.

(d) Accretion expense attributable to Ameren Missouri was recorded as a decrease to regulatory liabilities.

(e) The balance as of December 31, 2024, included an ARO related to the decommissioning of the Callaway Enter Center of \$648 million.

Deferred Compensation

As of December 31, 2024, and 2023, the present value of benefits to be paid for deferred compensation obligations was \$79 million and \$85 million, respectively, which was primarily reflected in "Other deferred credits and liabilities" on Ameren's consolidated balance sheet. Deferred compensation obligations are primarily recorded on the balance sheet of Ameren (parent).

Excise Taxes

Ameren Missouri and Ameren Illinois collect from their customers excise taxes, including municipal and state excise taxes and gross receipts taxes, that are levied on the sale or distribution of natural gas and electricity. The following table presents the excise taxes recorded on a gross basis in "Operating Revenues – Electric," "Operating Revenues – Natural gas" and "Operating Expenses – Taxes other than income taxes" on the statements of income for the years ended December 31, 2024, 2023, and 2022:

	2024		2023		2022	
Ameren Missouri	\$	169	\$	166	\$	162
Ameren Illinois		130		121		133
Ameren	\$	299	\$	287	\$	295

Allowance for Funds Used During Construction

The following table presents the average rate that was applied to eligible construction work in progress and the amounts of allowance for funds used during construction capitalized in 2024, 2023, and 2022:

	2024		2023		2022	
Average rate:						
Ameren Missouri		6 %		6 %		5 %
Ameren Illinois		6 %		6 %		5 %
Ameren:						
Allowance for equity funds used during construction	\$	76	\$	54	\$	43
Allowance for borrowed funds used during construction		56		48		26
Total Ameren	\$	132	\$	102	\$	69
Ameren Missouri:						
Allowance for equity funds used during construction	\$	58	\$	30	\$	24
Allowance for borrowed funds used during construction		39		27		13
Total Ameren Missouri	\$	97	\$	57	\$	37
Ameren Illinois:						
Allowance for equity funds used during construction	\$	17	\$	19	\$	18
Allowance for borrowed funds used during construction		15		17		12
Total Ameren Illinois	\$	32	\$	36	\$	30

Earnings per Share

Earnings per basic and diluted share are computed by dividing "Net Income Attributable to Ameren Common Shareholders" by the weighted-average number of basic and diluted common shares outstanding, respectively, during the applicable period. The weighted-average shares outstanding for earnings per diluted share includes the incremental effects resulting from performance share units, restricted stock units, and forward sale agreements relating to common stock when the impact would be dilutive, as calculated using the treasury stock method. For information regarding performance share units and restricted stock units, see Note 11 – Stock-based Compensation. For information regarding forward sale agreements, see Note 5 – Long-term Debt and Equity Financings.

The following table reconciles the weighted-average number of common shares outstanding to the diluted weighted-average number of common shares outstanding for the years ended December 31, 2024, 2023, and 2022:

	2024	2023	2022
Weighted-average Common Shares Outstanding – Basic	266.8	262.8	258.4
Assumed settlement of performance share units and restricted stock units	0.5	0.6	1.0
Dilutive effect of forward sale agreements	0.1	—	0.1
Weighted-average Common Shares Outstanding – Diluted^(a)	267.4	263.4	259.5

(a) There was an immaterial number of anti-dilutive securities excluded from the earnings per diluted share calculations for the years ended December 31, 2024, 2023, and 2022 related to performance share units and restricted stock units. Outstanding forward sale agreements as of December 31, 2024 that were anti-dilutive for the year ended December 31, 2024 were excluded from the earnings per diluted share calculation as calculated using the treasury stock method. The outstanding forward sale agreements as of December 31, 2023, were anti-dilutive for the year ended December 31, 2023, and excluded from the earnings per diluted share calculation as calculated using the treasury stock method. For additional information about the outstanding forward sale agreements, see Note 5 – Long-term Debt and Equity Financings.

Supplemental Cash Flow Information

The following table provides noncash financing and investing activity excluded from the statements of cash flows for the years ended December 31, 2024, 2023, and 2022:

	December 31, 2024			December 31, 2023			December 31, 2022		
	Ameren	Ameren Missouri	Ameren Illinois	Ameren	Ameren Missouri	Ameren Illinois	Ameren	Ameren Missouri	Ameren Illinois
Investing									
Accrued capital expenditures, including nuclear fuel expenditures	\$ 480	\$ 303	\$ 157	\$ 518	\$ 270	\$ 212	\$ 441	\$ 243	\$ 181
Net realized and unrealized gain (loss) – nuclear decommissioning trust fund	165	165	—	167	167	—	(218)	(218)	—
Return of investment in industrial development revenue bonds ^(a)	—	—	—	240	240	—	—	—	—
Financing									
Issuance of common stock for stock-based compensation	\$ 16	\$ —	\$ —	\$ 40	\$ —	\$ —	\$ 31	\$ —	\$ —
Issuance of common stock under the DRPlus	7	—	—	7	—	—	8	—	—
Termination of a financing agreement ^(a)	—	—	—	240	240	—	—	—	—

(a) In January 2023, Ameren Missouri and Audrain County mutually agreed to terminate a financing obligation agreement related to the CT energy center in Audrain County, which was scheduled to expire in December 2023. No cash was exchanged in connection with the termination of the agreement as the \$240 million principal amount of the financing obligation due from Ameren Missouri was equal to the amount of bond service payments due to Ameren Missouri.

NOTE 16 – SEGMENT INFORMATION

Ameren has four segments: Ameren Missouri, Ameren Illinois Electric Distribution, Ameren Illinois Natural Gas, and Ameren Transmission. The Ameren Missouri segment includes all of the operations of Ameren Missouri. Ameren Illinois Electric Distribution consists of the electric distribution business of Ameren Illinois. Ameren Illinois Natural Gas consists of the natural gas business of Ameren Illinois. Ameren Transmission primarily consists of the aggregated electric transmission businesses of Ameren Illinois and ATXI. The category called Other primarily includes Ameren (parent) activities and Ameren Services.

Ameren Missouri has one segment. Ameren Illinois has three segments: Ameren Illinois Electric Distribution, Ameren Illinois Natural Gas, and Ameren Illinois Transmission. See Note 1 – Summary of Significant Accounting Policies for additional information regarding the operations of Ameren Missouri, Ameren Illinois, and ATXI.

Segment operating revenues and a majority of operating expenses are directly recognized and incurred by Ameren Illinois in each Ameren Illinois segment. Common operating expenses, miscellaneous income and expenses, interest charges, and income tax expense are allocated by Ameren Illinois to each Ameren Illinois segment based on certain factors, which primarily relate to the nature of the cost. Additionally, Ameren Illinois Transmission earns revenue from transmission service provided to Ameren Illinois Electric Distribution, other retail electric suppliers, and wholesale customers. The transmission expense for Illinois customers who have elected to purchase their power from Ameren Illinois is recovered through a cost recovery mechanism with no net effect on Ameren Illinois Electric Distribution earnings, as costs are offset by corresponding revenues. Transmission revenues from these transactions are reflected in Ameren Transmission's and Ameren Illinois Transmission's operating revenues. An intersegment elimination at Ameren and Ameren Illinois occurs to eliminate these transmission revenues and expenses.

The CODMs for Ameren, Ameren Missouri, and Ameren Illinois are the Chief Executive Officer of Ameren and Chief Financial Officer of Ameren. The CODMs use net income to evaluate income generated from the segments to make decisions about resources allocated to each segment and assess segment performance. Net income is also used to monitor budget versus actual results when assessing segment performance.

The following tables present information about the reported GAAP revenue and specified items reflected in net income attributable to common shareholders and capital expenditures by segment at Ameren and Ameren Illinois for the years ended December 31, 2024, 2023, and 2022. Ameren, Ameren Missouri, and Ameren Illinois management review segment capital expenditure information rather than any individual or total asset amount.

Ameren

	Ameren Missouri	Ameren Illinois Electric Distribution	Ameren Illinois Natural Gas	Ameren Transmission	Other	Intersegment Eliminations	Ameren
2024							
External revenues	\$ 3,960	\$ 2,088	\$ 938	\$ 637	\$ —	\$ —	\$ 7,623
Intersegment revenues	33	1	—	144	—	(178)	—
Revenue	3,993	2,089	938	781	—	(178)	7,623
Fuel and purchased power ^(a)	(1,071)	(740)	—	—	—	130	(1,681)
Natural gas purchased for resale ^(a)	(60)	—	(260)	—	—	—	(320)
Other operations and maintenance expenses ^(a)	(1,050)	(619)	(230)	(70)	(48)	48	(1,969)
Other segment items							
Depreciation and amortization	(917)	(369)	(129)	(167)	(8)	—	(1,590)
Taxes other than income taxes	(372)	(75)	(78)	(9)	(13)	—	(547)
Other income, net	196	97	27	26	83	(12)	417
Interest charges	(244)	(98)	(63)	(117) ^(b)	(153)	12	(663)
Income taxes (benefit)	87	(50)	(56)	(120)	56	—	(83)
Noncontrolling interests – preferred stock dividends	(3)	(1)	—	(1)	—	—	(5)
Net income (loss) attributable to Ameren common shareholders	\$ 559	\$ 234	\$ 149	\$ 323	\$ (83)	\$ —	\$ 1,182
Interest income	\$ 8	\$ 28	\$ 1	\$ 6	\$ 10	\$ (12)	\$ 41
Capital expenditures	2,712	579	264	758	7	(1)	4,319
2023							
External revenues	\$ 3,825	\$ 2,217	\$ 897	\$ 561	\$ —	\$ —	\$ 7,500
Intersegment revenues	34	1	—	116	—	(151)	—
Revenue	3,859	2,218	897	677	—	(151)	7,500
Fuel and purchased power ^(a)	(997)	(933)	—	—	—	118	(1,812)
Natural gas purchased for resale ^(a)	(79)	—	(276)	—	—	—	(355)
Other operations and maintenance expenses ^(a)	(1,003)	(532)	(237)	(60)	(67)	33	(1,866)
Other segment items							
Depreciation and amortization	(783)	(351)	(108)	(138)	(7)	—	(1,387)
Taxes other than income taxes	(360)	(75)	(67)	(8)	(12)	—	(522)
Other income, net	130	103	30	28	62	(5)	348
Interest charges	(227)	(89)	(55)	(96) ^(b)	(104)	5	(566)
Income taxes (benefit)	8	(82)	(50)	(106)	47	—	(183)
Noncontrolling interests – preferred stock dividends	(3)	(1)	—	(1)	—	—	(5)
Net income (loss) attributable to Ameren common shareholders	\$ 545	\$ 258	\$ 134	\$ 296	\$ (81)	\$ —	\$ 1,152
Interest income	\$ 11	\$ 19	\$ 1	\$ 2	\$ 5	\$ (5)	\$ 33
Capital expenditures	1,760	752	299	804	9	(27)	3,597
2022							
External revenues	\$ 4,012	\$ 2,255	\$ 1,180	\$ 510	\$ —	\$ —	\$ 7,957
Intersegment revenues	34	1	—	105	—	(140)	—
Revenue	4,046	2,256	1,180	615	—	(140)	7,957
Fuel and purchased power ^(a)	(1,150)	(984)	—	—	—	114	(2,020)
Natural gas purchased for resale ^(a)	(104)	—	(553)	—	—	—	(657)
Other operations and maintenance expenses ^(a)	(1,028)	(580)	(253)	(60)	(42)	26	(1,937)
Other segment items							
Depreciation and amortization	(732)	(332)	(98)	(123)	(4)	—	(1,289)
Taxes other than income taxes	(363)	(75)	(82)	(9)	(10)	—	(539)
Other income, net	99	60	19	17	32	(1)	226
Interest charges	(213)	(74)	(44)	(84) ^(b)	(72)	1	(486)
Income taxes (benefit)	10	(68)	(46)	(92)	20	—	(176)
Noncontrolling interests – preferred stock dividends	(3)	(1)	—	(1)	—	—	(5)
Net income (loss) attributable to Ameren common shareholders	\$ 562	\$ 202	\$ 123	\$ 263	\$ (76)	\$ —	\$ 1,074
Interest income	\$ 28	\$ 7	\$ —	\$ —	\$ 1	\$ (1)	\$ 35
Capital expenditures	1,690	621	308	741	7	(16)	3,351

(a) Significant segment expense that is regularly provided to the CODMs. Intersegment expenses are included within the amounts shown.

(b) Ameren Transmission interest charges include an allocation of financing costs from Ameren (parent).

Ameren Illinois

	Ameren Illinois Electric Distribution	Ameren Illinois Natural Gas	Ameren Illinois Transmission	Intersegment Eliminations	Ameren Illinois
2024					
External revenues	\$ 2,089	\$ 938	\$ 445	\$ —	\$ 3,472
Intersegment revenues	—	—	119	(119)	—
Revenue	2,089	938	564	(119)	3,472
Purchased power ^(a)	(740)	—	—	119	(621)
Natural gas purchased for resale ^(a)	—	(260)	—	—	(260)
Other operations and maintenance expenses ^(a)	(619)	(230)	(57)	—	(906)
Other segment items					
Depreciation and amortization	(369)	(129)	(121)	—	(619)
Taxes other than income taxes	(75)	(78)	(4)	—	(157)
Other income, net	97	27	23	—	147
Interest charges	(98)	(63)	(80)	—	(241)
Income taxes	(50)	(56)	(87)	—	(193)
Noncontrolling interests – preferred stock dividends	(1)	—	(1)	—	(2)
Net income available to common shareholder	\$ 234	\$ 149	\$ 237	\$ —	\$ 620
Interest income	\$ 28	\$ 1	\$ 3	\$ —	\$ 32
Capital expenditures	579	264	624	—	1,467
2023					
External revenues	\$ 2,218	\$ 897	\$ 367	\$ —	\$ 3,482
Intersegment revenues	—	—	113	(113)	—
Revenue	2,218	897	480	(113)	3,482
Purchased power ^(a)	(933)	—	—	113	(820)
Natural gas purchased for resale ^(a)	—	(276)	—	—	(276)
Other operations and maintenance expenses ^(a)	(532)	(237)	(49)	—	(818)
Other segment items					
Depreciation and amortization	(351)	(108)	(97)	—	(556)
Taxes other than income taxes	(75)	(67)	(4)	—	(146)
Other income, net	103	30	23	—	156
Interest charges	(89)	(55)	(60)	—	(204)
Income taxes	(82)	(50)	(77)	—	(209)
Noncontrolling interests – preferred stock dividends	(1)	—	(1)	—	(2)
Net income available to common shareholder	\$ 258	\$ 134	\$ 215	\$ —	\$ 607
Interest income	\$ 19	\$ 1	\$ 1	\$ —	\$ 21
Capital expenditures	752	299	680	—	1,731
2022					
External revenues	\$ 2,256	\$ 1,180	\$ 320	\$ —	\$ 3,756
Intersegment revenues	—	—	104	(104)	—
Revenue	2,256	1,180	424	(104)	3,756
Purchased power ^(a)	(984)	—	—	104	(880)
Natural gas purchased for resale ^(a)	—	(553)	—	—	(553)
Other operations and maintenance expenses ^(a)	(580)	(253)	(49)	—	(882)
Other segment items					
Depreciation and amortization	(332)	(98)	(84)	—	(514)
Taxes other than income taxes	(75)	(82)	(4)	—	(161)
Other income, net	60	19	17	—	96
Interest charges	(74)	(44)	(50)	—	(168)
Income taxes	(68)	(46)	(65)	—	(179)
Noncontrolling interests – preferred stock dividends	(1)	—	(1)	—	(2)
Net income available to common shareholder	\$ 202	\$ 123	\$ 188	\$ —	\$ 513
Interest income	\$ 7	\$ —	\$ —	\$ —	\$ 7
Capital expenditures	621	308	672	—	1,601

(a) Significant segment expense that is regularly provided to the CODMs. Intersegment expenses are included within the amounts shown.

The following tables present disaggregated GAAP revenues by segment at Ameren and Ameren Illinois for the years ended December 31, 2024, 2023, and 2022. Economic factors affect the nature, timing, amount, and uncertainty of revenues and cash flows in a similar manner across customer classes. Revenues from alternative revenue programs have a similar distribution among customer classes as revenues from contracts with customers. Other revenues not associated with contracts with customers are presented in the Other customer classification, along with electric transmission and off-system sales and capacity revenues.

Ameren

	Ameren Missouri	Ameren Illinois Electric Distribution	Ameren Illinois Natural Gas	Ameren Transmission	Intersegment Eliminations	Ameren
2024						
Residential	\$ 1,638	\$ 1,254	\$ —	\$ —	\$ —	\$ 2,892
Commercial	1,313	680	—	—	—	1,993
Industrial	311	178	—	—	—	489
Other	585	(23)	—	781	(177)	1,166
Total electric revenues	\$ 3,847	\$ 2,089	\$ —	\$ 781	\$ (177)	\$ 6,540
Residential	\$ 90	\$ —	\$ 661	\$ —	\$ —	\$ 751
Commercial	37	—	166	—	—	203
Industrial	4	—	10	—	—	14
Other	15	—	101	—	(1)	115
Total gas revenues	\$ 146	\$ —	\$ 938	\$ —	\$ (1)	\$ 1,083
Total revenues ^(a)	\$ 3,993	\$ 2,089	\$ 938	\$ 781	\$ (178)	\$ 7,623
2023						
Residential	\$ 1,577	\$ 1,344	\$ —	\$ —	\$ —	\$ 2,921
Commercial	1,280	747	—	—	—	2,027
Industrial	306	186	—	—	—	492
Other	531	(59)	—	677	(150)	999
Total electric revenues	\$ 3,694	\$ 2,218	\$ —	\$ 677	\$ (150)	\$ 6,439
Residential	\$ 100	\$ —	\$ 657	\$ —	\$ —	\$ 757
Commercial	46	—	164	—	—	210
Industrial	5	—	14	—	—	19
Other	14	—	62	—	(1)	75
Total gas revenues	\$ 165	\$ —	\$ 897	\$ —	\$ (1)	\$ 1,061
Total revenues ^(a)	\$ 3,859	\$ 2,218	\$ 897	\$ 677	\$ (151)	\$ 7,500
2022						
Residential	\$ 1,578	\$ 1,325	\$ —	\$ —	\$ —	\$ 2,903
Commercial	1,219	768	—	—	—	1,987
Industrial	290	199	—	—	—	489
Other	762	(36)	—	615	(139)	1,202
Total electric revenues	\$ 3,849	\$ 2,256	\$ —	\$ 615	\$ (139)	\$ 6,581
Residential	\$ 119	\$ —	\$ 846	\$ —	\$ —	\$ 965
Commercial	56	—	221	—	—	277
Industrial	7	—	41	—	—	48
Other	15	—	72	—	(1)	86
Total gas revenues	\$ 197	\$ —	\$ 1,180	\$ —	\$ (1)	\$ 1,376
Total revenues ^(a)	\$ 4,046	\$ 2,256	\$ 1,180	\$ 615	\$ (140)	\$ 7,957

(a) The following table presents increases/(decreases) in revenues from alternative revenue programs and other revenues not from contracts with customers for the years ended December 31, 2024, 2023, and 2022:

	Ameren Missouri	Ameren Illinois Electric Distribution	Ameren Illinois Natural Gas	Ameren Transmission	Ameren
2024					
Revenues from alternative revenue programs	\$ 4	\$ (43)	\$ (3)	\$ 33	\$ (9)
Other revenues not from contracts with customers	7 ^(a)	10	2	—	19 ^(a)
2023					
Revenues from alternative revenue programs	\$ (5)	\$ 116	\$ 49	\$ 19	\$ 179
Other revenues not from contracts with customers	(9) ^(a)	7	2	—	— ^(a)
2022					
Revenues from alternative revenue programs	\$ 17	\$ 89	\$ (19)	\$ (9)	\$ 78
Other revenues not from contracts with customers	(103) ^{(a)(b)}	6	3	—	(94) ^{(a)(b)}

(a) Includes net realized gains and losses on derivative power contracts.

(b) Includes \$10 million for insurance recoveries related to lost sales associated with the Callaway Energy Center maintenance outage for the year ended December 31, 2022.

Ameren Illinois

	Ameren Illinois Electric Distribution	Ameren Illinois Natural Gas	Ameren Illinois Transmission	Intersegment Eliminations	Ameren Illinois
2024					
Residential	\$ 1,254	\$ 661	\$ —	\$ —	\$ 1,915
Commercial	680	166	—	—	846
Industrial	178	10	—	—	188
Other	(23)	101	564	(119)	523
Total revenues ^(a)	\$ 2,089	\$ 938	\$ 564	\$ (119)	\$ 3,472
2023					
Residential	\$ 1,344	\$ 657	\$ —	\$ —	\$ 2,001
Commercial	747	164	—	—	911
Industrial	186	14	—	—	200
Other	(59)	62	480	(113)	370
Total revenues ^(a)	\$ 2,218	\$ 897	\$ 480	\$ (113)	\$ 3,482
2022					
Residential	\$ 1,325	\$ 846	\$ —	\$ —	\$ 2,171
Commercial	768	221	—	—	989
Industrial	199	41	—	—	240
Other	(36)	72	424	(104)	356
Total revenues ^(a)	\$ 2,256	\$ 1,180	\$ 424	\$ (104)	\$ 3,756

(a) The following table presents increases/(decreases) in revenues from alternative revenue programs and other revenues not from contracts with customers for the Ameren Illinois segments for the years ended December 31, 2024, 2023, and 2022:

	Ameren Illinois Electric Distribution	Ameren Illinois Natural Gas	Ameren Illinois Transmission	Ameren Illinois
2024				
Revenues from alternative revenue programs	\$ (43)	\$ (3)	\$ 29	\$ (17)
Other revenues not from contracts with customers	10	2	—	12
2023				
Revenues from alternative revenue programs	\$ 116	\$ 49	\$ 12	\$ 177
Other revenues not from contracts with customers	7	2	—	9
2022				
Revenues from alternative revenue programs	\$ 89	\$ (19)	\$ (7)	\$ 63
Other revenues not from contracts with customers	6	3	—	9

Additional Notes Relating to the Statement of Cash Flows:

Reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet for the year ended December 31, 2024:

Cash and Cash Equivalents at End of Period	\$	57,704
Related amounts on the Balance Sheet:		
Line 35 - Cash	\$	47,704
Line 37 - Working Fund		10,000
Line 38 - Temporary Cash Investments		—
	\$	57,704

Amount of interest paid (net of amounts capitalized) for the year ended December 31, 2024 = \$243,782,730

Amount of income tax refunds, net of payments, for the year ended December 31, 2024 = \$136,207,144

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year									
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income									
3	Preceding Quarter/Year to Date Changes in Fair Value									
4	Total (lines 2 and 3)								548,817,504	548,817,50
5	Balance of Account 219 at End of Preceding Quarter/Year									
6	Balance of Account 219 at Beginning of Current Year									
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income									
8	Current Quarter/Year to Date Changes in Fair Value									
9	Total (lines 7 and 8)								562,303,136	562,303,13
10	Balance of Account 219 at End of Current Quarter/Year									

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SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	26,413,371,902	25,637,754,984	775,616,918				
4	Property Under Capital Leases	91,855,431	91,855,431					
5	Plant Purchased or Sold							
6	Completed Construction not Classified							
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	26,505,227,333	25,729,610,415	775,616,918				
9	Leased to Others							
10	Held for Future Use	19,159,749	19,159,749					
11	Construction Work in Progress	995,267,308	989,841,643	5,425,665				
12	Acquisition Adjustments	31,627,358	31,776,380	(149,022)				
13	Total Utility Plant (8 thru 12)	27,551,281,748	26,770,388,187	780,893,561				
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	10,066,481,231	9,820,122,939	246,358,292				
15	Net Utility Plant (13 less 14)	17,484,800,517	16,950,265,248	534,535,269				
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	9,364,770,240	9,124,670,132	240,100,108				
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							

20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	670,033,970	663,676,426	6,357,544				
22	Total in Service (18 thru 21)	10,034,804,210	9,788,346,558	246,457,652				
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment	31,677,021	31,776,381	(99,360)				
33	Total Accum Prov (equals 14) (22,26,30,31,32)	10,066,481,231	9,820,122,939	246,358,292				

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases

Leases recorded in accordance with Accounting Standards Code 842 - Leases and included in FERC property accounts as provided for in FERC Docket No. AI19-1-000:

\$	25,075,020	Railcars	
	65,776,908	Land - Solar Generation	
	1,003,503	Land - General Plant	
	91,855,431	Operating Leases	

(b) Concept: DepreciationUtilityPlantInService

Accumulated amortization related to leases recorded in accordance with Accounting Standards Code 842 - Leases and included in FERC property accounts as provided for in FERC Docket No. AI19-1-000:

\$	20,098,215	Railcars	
	1,902,449	Land - Solar Generation	
	958,644	Land - General Plant	
	22,959,308	Operating Leases	

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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication	(255)	18,094,345		9,808,959	8,285,131
3	Nuclear Materials	153,016,655	64,602,386		79,043,394	138,575,647
4	Allowance for Funds Used during Construction	10,182,722	13,685,775		9,072,142	14,796,355
5	(Other Overhead Construction Costs, provide details in footnote)	1,055,956	704,313		698,254	1,062,015
6	SUBTOTAL (Total 2 thru 5)	164,255,078	97,086,819		98,622,749	162,719,148
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)	9,016,711	99,482,107		3,083,841	105,414,977
9	In Reactor (120.3)	246,216,079	166,088			246,382,167
10	SUBTOTAL (Total 8 & 9)	255,232,790	99,648,195		3,083,841	351,797,144
11	Spent Nuclear Fuel (120.4)	2,022,587,714	2,918,063			2,025,505,777
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	2,119,888,805		(80,366,749)		2,200,255,554
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	322,186,777	199,653,077	80,366,749	101,706,590	339,766,515
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					

22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					
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FOOTNOTE DATA

(a) Concept: OtherOverheadConstructionCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabrication

Applies to line 5, all columns:
Includes payroll, benefits and other miscellaneous employee expenses.

(b) Concept: FabricationCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationAdditions

Current Year Fabrication Expenses	\$	17,143,666
AFUDC accrued on Fabrication		950,679
	\$	18,094,345

(c) Concept: SpentNuclearFuelAdditions

Transfer In-Stock to Spent Fuel for previous reload true-ups.

(d) Concept: FabricationCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Applies to lines 2-5, column (e):
Transfer In-Process to In-Stock and In-Reactor.

(e) Concept: NuclearFuelMaterialsAndAssembliesInStockOtherReductions

Transfer In-Stock to In-Reactor and Spent Fuel for previous reload true-ups.

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

- Report below the original cost of electric plant in service according to the prescribed accounts.
- In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
- Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
- For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
- Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
- Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
- Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
- For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
- For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents	122,963,007	29,960,637				152,923,644
4	(303) Miscellaneous Intangible Plant	868,463,806	123,733,092	2,445,930			989,750,968
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	991,426,813	153,693,729	2,445,930			1,142,674,612
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	15,685,418				(979,537)	14,705,881
9	(311) Structures and Improvements	350,323,213	18,360,378	117,437,234		(1,257,331)	249,989,026
10	(312) Boiler Plant Equipment	2,922,521,391	46,803,501	576,105,230		(20,000)	2,393,199,662
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	639,016,621	17,719,662	158,119,602		(423,835)	498,192,846
13	(315) Accessory Electric Equipment	311,906,397	13,937,049	61,695,575		101,383	264,249,254
14	(316) Misc. Power Plant Equipment	78,360,678	2,345,164	16,791,123		(1,342,171)	62,572,548

15	(317) Asset Retirement Costs for Steam Production	81,202,841	15,787,993				96,990,834
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	4,399,016,559	114,953,747	930,148,764		(3,921,491)	3,579,900,051
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights	9,793,884					9,793,884
19	(321) Structures and Improvements	1,000,974,938	10,659,518	1,632,864			1,010,001,592
20	(322) Reactor Plant Equipment	1,427,828,336	7,921,219	1,700,485			1,434,049,070
21	(323) Turbogenerator Units	549,665,373	3,269,959	(10,236)			552,945,568
22	(324) Accessory Electric Equipment	304,242,502	1,365,980	178,692			305,429,790
23	(325) Misc. Power Plant Equipment	224,704,070	31,955,089	2,372,545		(131,249)	254,155,365
24	(326) Asset Retirement Costs for Nuclear Production	92,749,580					92,749,580
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	3,609,958,683	55,171,765	5,874,350		(131,249)	3,659,124,849
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	18,104,859					18,104,859
28	(331) Structures and Improvements	60,348,631	5,065,010	261,466			65,152,175
29	(332) Reservoirs, Dams, and Waterways	136,356,219	1,160,029	137,153			137,379,095
30	(333) Water Wheels, Turbines, and Generators	347,340,864	(117,331)	1,676			347,221,857
31	(334) Accessory Electric Equipment	66,128,238	(85,429)			(55,000)	65,987,809
32	(335) Misc. Power Plant Equipment	16,142,282	1,378,072	720,413		486,219	17,286,160
33	(336) Roads, Railroads, and Bridges	575,437					575,437
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	644,996,530	7,400,351	1,120,708		431,219	651,707,392
36	D. Other Production Plant						
37	(340) Land and Land Rights	10,247,558	65,775,328				76,022,886
38	(341) Structures and Improvements	131,416,682	65,916,602	193,841			197,139,443

39	(342) Fuel Holders, Products, and Accessories	48,863,370	1,573,942	416,028			50,021,284
40	(343) Prime Movers						
41	(344) Generators	2,022,187,726	667,381,489	15,190,525		423,835	2,674,802,525
42	(345) Accessory Electric Equipment	217,752,021	209,419,150	1,177,714			425,993,457
43	(346) Misc. Power Plant Equipment	12,414,460	4,097,357	1,475,528			15,036,289
44	(347) Asset Retirement Costs for Other Production	53,942,767	8,844,037				62,786,804
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	2,496,824,584	1,023,007,905	18,453,636		423,835	3,501,802,688
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	11,150,796,356	1,200,533,768	955,597,458		(3,197,686)	11,392,534,980
47	3. Transmission Plant						
48	(350) Land and Land Rights	63,328,091	216,415			148,507	63,693,013
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	9,565,836	12,503	40,767		1,223,568	10,761,140
50	(353) Station Equipment	700,873,307	175,068,377	11,761,519			864,180,165
51	(354) Towers and Fixtures	104,554,452	745,562	262,470			105,037,544
52	(355) Poles and Fixtures	800,434,576	82,832,873	57,149			883,210,300
53	(356) Overhead Conductors and Devices	455,406,140	23,638,412	176,622			478,867,930
54	(357) Underground Conduit						
55	(358) Underground Conductors and Devices						
56	(359) Roads and Trails	71,788					71,788
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,134,234,190	282,514,142	12,298,527		1,372,075	2,405,821,880
59	4. Distribution Plant						
60	(360) Land and Land Rights	41,007,217	499,015			(90,416)	41,415,816
61	(361) Structures and Improvements	17,932,906	132,393	40,160			18,025,139
62	(362) Station Equipment	1,490,443,568	282,058,315	7,448,479			1,765,053,404

63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	1,644,200,054	141,028,879	7,453,414		(39,246)	1,777,736,273
65	(365) Overhead Conductors and Devices	1,761,848,025	96,802,444	17,849,649		4,922,626	1,845,723,446
66	(366) Underground Conduit	785,734,448	68,419,196	682,956		(4,977,625)	848,493,063
67	(367) Underground Conductors and Devices	1,292,654,071	178,174,205	17,495,532		94,247	1,453,426,991
68	(368) Line Transformers	619,600,661	40,863,866	5,713,828		(4,806)	654,745,893
69	(369) Services	449,035,114	27,773,512	757,957		(1,096,981)	474,953,688
70	(370) Meters	284,624,097	44,038,146	12,493,634			316,168,609
71	(371) Installations on Customer Premises	164,613					164,613
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	250,923,857	24,692,079	3,347,945		1,096,979	273,364,970
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	8,638,168,631	904,482,050	73,283,554		(95,222)	9,469,271,905
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights	16,437,690	434,853				16,872,543

87	(390) Structures and Improvements	486,585,724	76,964,262	3,009,069		2,751,660	563,292,577
88	(391) Office Furniture and Equipment	191,331,226	25,284,257	19,935,371		(2,141,375)	194,538,737
89	(392) Transportation Equipment	192,791,902	34,863,217	14,809,499		(460,548)	212,385,072
90	(393) Stores Equipment	7,410,885	429,776	83,179			7,757,482
91	(394) Tools, Shop and Garage Equipment	46,495,939	3,370,168	500,757		729,201	50,094,551
92	(395) Laboratory Equipment	8,072,091	94,254	193,592		7,691	7,980,444
93	(396) Power Operated Equipment	24,889,548	859,038	1,926,849		841,011	24,662,748
94	(397) Communication Equipment	218,007,714	25,357,386	9,668,949		10,365	233,706,516
95	(398) Miscellaneous Equipment	4,469,935	1,608,050	2,924		(610,285)	5,464,776
96	SUBTOTAL (Enter Total of lines 86 thru 95)	1,196,492,654	169,265,261	50,130,189		1,127,720	1,316,755,446
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant	2,551,592					2,551,592
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	1,199,044,246	169,265,261	50,130,189		1,127,720	1,319,307,038
100	TOTAL (Accounts 101 and 106)	24,113,670,236	2,710,488,950	1,093,755,658		(793,113)	25,729,610,415
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	24,113,670,236	2,710,488,950	1,093,755,658		(793,113)	25,729,610,415

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ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
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47	TOTAL					

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

- Report separately each property held for future use at end of the year having an original cost of \$250,000 or more. Group other items of property held for future use.
- For property having an original cost of \$250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Prairie - Dell Sub Site - 138/34 KV Substation - Distribution	12/01/1999	12/01/2027	333,772
3	Highlands Substation - Distribution	11/01/2008	12/01/2029	529,892
4	New Ballwin Substation - Distribution	09/01/2007	12/01/2029	814,339
5	Bugle 345-138 KV Sub site	01/01/2014	12/01/2025	5,419,281
6	Montgomery Solar Field	09/01/2016	12/01/2026	297,000
7	Rivermines Operating Center - Land	05/01/2019	12/01/2025	941,430
8	Dougherty Ferry Substation	12/01/2021	12/01/2027	8,105,803
9	Jefferson City Storeroom, Storage Yard	09/01/2021	12/01/2025	908,868
10				
21	Other Property:			
22	Other properties having an individual value less than \$250,000.			1,809,364
47	TOTAL			19,159,749

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or \$1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Renewable Energy Center - Vandalia - Facility	57,371,993
2	Castle Bluff Simple Cycle Generation	50,230,504
3	Renewable Energy Center - Bowling Green Facility	40,955,731
4	Combustion Turbine Generation AUD Dual Fuel Conversion	23,558,300
5	Labadie Unit 3 A,B,C ESP Upgrade	20,711,774
6	Highway N 161 kV Statcom	19,878,597
7	Page Bulk Substation Upgrade - Substation - C	16,828,204
8	Berkeley Station Upgrades	15,205,509
9	Reform Renewable Energy Center	14,199,048
10	Callaway Center Chillers Replacement	13,343,474
11	Mason 138kV Station Upgrades	12,123,193
12	Callaway Security System Upgrade	11,030,721
13	Labade Unit 3 Main Turbine and Valve Component	10,839,262
14	Callaway Plant Computer Upgrade	10,743,837
15	Taum Sauk Unit 1 GSU Transformer Upgrade	10,584,465
16	Osage Unit 2 Turbine Upgrade	9,906,438
17	Mobile Transformer 345/138kV-UE	9,358,785
18	Callaway NI Drawers Replacement	9,357,459
19	Osage Unit 4 Turbine Upgrade	8,748,314
20	Condition Based Maintenance-River Roads Substation-Substation-C	8,230,300
21	Condition Based Maintenance-Dellwood Substation Upgrade-Substation-C	8,043,988
22	Ivory 12 kV Substations-Substation C	7,940,978
23	Labadie Unit 3 Generator Field Rewind	7,201,078
24	Labadie Unit 2 316 Compliance	7,124,854
25	Callaway DCS Polisher Upgrade	6,798,290
26	Callaway MCC Buckets 2020-2025	6,713,333
27	Condition Based Maintenance-Pasadena-Substation-C	6,682,844
28	Labadie - U3 HPBFP Turbine Controls EC	6,632,779
29	Callaway Unit Auxiliary Transformer XMA02 Upgrade	6,380,095

30	Callaway Phase 1 200 Series PA07 in Switchyard	6,262,376
31	Condition Based Maintenance-Cool Valley Substation Upgrade-Substation-C	5,891,431
32	Rootbeer (J976) - Ring Bus	5,867,839
33	Callaway A Safeguard Transformer Replacement	5,767,589
34	Labadie Unit 3 Excitation Upgrade J05Q9	5,695,458
35	Callaway Start-Up Transformer Replacement	5,549,214
36	Callaway RF27 Turbine Work	5,544,555
37	Ameren Headquarters UPS-ATS Replacement	5,477,021
38	High Prairie Active Bat Curtailment	5,188,204
39	Fleet Charging Infrastructure	5,077,597
40	Renewable Energy Center - Bowling Green Land	5,053,538
41	Renewable Energy Center - Vandalia - Land	4,944,369
42	Maline 4 Upgrade	4,897,487
43	Osage BOP Controls	4,621,487
44	Conway 138 kV Statcom	4,588,360
45	C Upgrade Blair 026 - PILC W Phase A	4,563,398
46	345/161kV 560 MVA Spare Transformer	4,552,627
47	BLAND-FRANK-3 (345kV)-Rebuild	4,355,465
48	Warson 1 Upgrade	4,144,642
49	Gray Summit Aging Infrastructure	3,943,469
50	VIAD-76 34kV Upgrade D	3,900,823
51	Callaway Station Upgrades	3,829,570
52	Berkeley 4 Upgrade	3,651,953
53	Friedens Substation, Upgrade Station C	3,594,788
54	Taum Sauk Unit 2 GSU Transformer Upgrade	3,563,482
55	Fleet Battery Storage	3,505,868
56	C-Upgrade Potosi 484-52, LAT-2070	3,475,214
57	Mason Transformer 2 Upgrade	3,450,070
58	Callaway F-71 Upgrade Otterville - Smithton	3,353,303
59	St. Francois 138/345 kV AI	3,165,565
60	Sioux-316B Compliance	3,119,476
61	Combustion Turbine Generation PNO 4A GG Minor HGP Replacement	3,084,372
62	Callaway SFP Cooling Alternatives	3,082,338
63	Condition Based Maintenance-Luxemburg Substation Upgrade Substation-C	3,068,439
64	Kinloch 005-12kV Upgrade	3,032,138
65	Transformers Spare 34-12kV & 34-4kV	3,024,755
66	Callaway License Renewal AEPS Cable Upgrade	3,015,599

67	Labadie Unit 1 & Unit 2 HPBFPT Cap Spare Rotor	2,966,803
68	Scarlet 345kV Ring Bus	2,943,717
69	OTU-Rock Hill 139-6 Fair Oaks Phase 1	2,941,362
70	Labadie - Unit 3 Main Turbine Controls	2,932,400
71	Callaway A MDAFP Cable Replacement	2,857,097
72	Labadie FGD Retrofit	2,847,415
73	Labadie Ground Water Improvement	2,628,542
74	Scarlet DC 345/161 kV Line	2,612,808
75	Callaway V54 SPV Digital Relay Upgrade	2,611,979
76	Viburnum Substation Add Line Breakers	2,610,782
77	Glenwood Substation Upgrade - Substation - C	2,584,976
78	Scarlet Easements SCAR-WCITY-5690	2,508,152
79	Callaway CCW HX A End-Bell Replacement	2,430,401
80	C-Upgrade Tan-Tar-A 593-53&56 Phase 4	2,390,962
81	Berkeley 138kV Underground AI Upgrade	2,384,149
82	DL-Teradata Decom Project 2 Union Electric Company	2,372,016
83	Marshall 1 Upgrade	2,326,990
84	Callaway CCW HX B End-Bell Replacement	2,319,071
85	Gratiot Northwest 1267 Ref 0A321	2,313,916
86	Taum Sauk Unit 2 Exciter Upgrade	2,308,551
87	High Prairie Lightning Detection	2,304,507
88	Rush Island BESS	2,222,416
89	Saint Louisi Headquarters Capstone J0VSZ	2,210,358
90	S&T Lodestar Replacement - 23 - 25 - Union Electric Company	2,187,842
91	Sioux Unit 2 NOX Control	2,171,523
92	Taum Sauk Unit 1 Exciter Upgrade	2,165,727
93	Labadie S2-S3 Conveyors Upgrade	2,159,911
94	Osage Unit 2 Generator Rotor Rewind	2,114,679
95	Labadie Construction Trailer Park Exp	2,073,721
96	Fountain Lakes - 2nd Unit - Substation C	2,050,462
97	High Prairie Bat Mitigation	1,996,630
98	Spare HV Circuit Breakers MO	1,990,665
99	MSD Lemay PS3 Customer Substation-Substation-C	1,930,535
100	Labadie Unit 4 4160V BREAKER Replacement	1,912,658
101	Mason 345/138kV Transformer 1 Upgrade	1,889,304
102	Berkeley 1 Upgrade	1,886,521
103	Mason 345kV Aging Infrastructure	1,861,756

104	Sioux 138kV Station Upgrades	1,845,635
105	Keokuk Substations ST Protection Upgrades	1,836,310
106	Digital Architecture Database 24-25	1,834,122
107	Labadie Unit 2 Generator Field Rewind	1,816,173
108	Private Long Term Evolution Missouri Metro - Union Electric Company	1,786,481
109	Multi Source Data Migration - Union Electric Company	1,783,234
110	Callaway NG Breaker Size 5 Starter Upgrade	1,777,598
111	Labadie Replacement Unit 4 A/B/C Casing/Suc Valve	1,771,852
112	Labadie Bus 3 Upgrades	1,753,854
113	Energy Delivery Click & Maximo Optimization 24-2	1,752,905
114	Condition Based Maintenance-Magnolia Substation-Substation C	1,751,379
115	Clark - Dillion 6132 138kV Union Electric Company-ROW	1,731,352
116	Baumgartner 138kV Aging Infrastructure	1,706,128
117	Microsoft Voice Union Electric Company	1,686,906
118	Cape-Kelso-2, Kelso-Miner-2 Tie In	1,684,834
119	Imperial Substation Upgrade W Unit and Switchgear	1,676,071
120	Highway N 161 kV Statcom Position	1,674,735
121	Callaway Chessel Recorder Replacement	1,646,580
122	Labadie Unit 2 Black Start Capability	1,631,167
123	Jays 161 kv Ring Bus	1,610,286
124	Condition Based Maintenance-Loughborough Underground Upgrade Substation-Substation C	1,586,164
125	Overton 345kV Ring Bus EXP	1,573,203
126	C-Upgrade Gimblin 317 - PILC	1,529,530
127	Mobile Substation N Upgrade	1,506,597
128	Rivermines-Clark-2 Union Electric Company-ROW	1,498,406
129	Overton-Moberly-1 16kV Union Electric Company-ROW	1,497,868
130	Labadie Unit 4 Replacement Reheater (Headers & Assembly)	1,487,727
131	Foxboro 005-12kV Upgrade	1,480,370
132	OTU-Castlewood 197-57 State Park	1,475,714
133	Condition Based Maintenance=Yorkshire Substation Upgrade Switchgear W-Substation C	1,473,160
134	Sioux 345kV Upgrades	1,441,932
135	Switchgear Spares 15kV	1,438,207
136	Moline-74 Dunn	1,421,442
137	Selma-Rivermines-2 138kV Union Electric Company-ROW	1,414,325
138	Meramec - JOCM 6876 AI 2022	1,384,600
139	Page Bulk Substation Upgrade-6090 XMSN-C	1,377,608

140	345/138kV 700 MVA Spare Transformer Union Electric Company	1,346,500
141	Lakeside 138/34 Transformer 1 Upgrade	1,344,287
142	Condition Based Maintenance - Upgrade Mobile Substation D	1,330,917
143	Labadie Unit 3 Soot Blowing System Controls	1,328,910
144	Dorsett Training Building Next Generation	1,317,643
145	Pike 12kV Upgrade-69kV Substation	1,307,464
146	L-Montgomery-4 Reroute (Scarlet)	1,298,864
147	Solar Facility - Gratiot	1,287,211
148	Keokuk BOP Controls	1,284,136
149	Keokuk 69kV Terminal Posn	1,283,084
150	Osage Unit 4 Generator Rotor Rewind	1,272,491
151	Callaway EDG Relay Upgrade	1,250,681
152	RUSL-Underground West Side Cond	1,246,740
153	Callaway PK13/PK14 Battery Replacement	1,233,608
154	Transformer 112MVA Spare 5A 2026	1,230,566
155	Callaway CMB Roof Replacement	1,208,054
156	Grand Glaze 581-51 Oasis Lakeport	1,197,543
157	Transformer 112MVA Spare 5B 2026	1,192,585
158	Condition Based Maintenance-Delmar W, Rebuild-Substation C	1,173,169
159	Spencer Creek Upgrade Relay and Southwest	1,170,738
160	Labadie SO3 System Upgrade	1,154,040
161	Vanhorn 345kV (J1352) NU RB	1,148,542
162	R-Ballwin-4585 - New Tower Lights	1,144,177
163	Rush Island 345kV Relay Upgrade	1,127,363
164	Lockwood W - Switchgear	1,120,278
165	Bugle 345kV Line Rebuild - East	1,117,318
166	Callaway Spare RCP Motor Procurement	1,109,083
167	Sioux NOx Control	1,578,406
168	Conditon Based Maintenance-Loughborough Substation Site	1,048,262
169	Callaway High Side Breaker (2)	1,041,962
170	Adna (J1107) Ring Bus (New Unit)	1,037,716
171	Combustion Turbine Generation Rock CO2 Fire Supplement System Replacement	1,036,944
172	Test/Training Keokuk Turbine	1,035,583
173	Montgomery 345 Aging Infrastructure	1,018,860
174	Keokuk Spillway Apron Replacement	1,018,596
175	Sioux Capital Spare Fan Blades	1,017,903
176	Switchgear Spares 38kV	1,015,548

177	Transformer Spare 22 34/4kV 2024	1,009,086
178	C-Upgrade Blair 026 - PILC D Phase B	1,000,125
179	Martin Luther King (0A321) 1834 Northwest Voltage Transformer CAB Upgrade	1,136,893
180	MINOR PROJECTS	201,625,982
43	Total	989,841,643

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
Section A. Balances and Changes During Year					
1	Balance Beginning of Year	9,084,944,710	9,084,944,710		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	713,079,518	(a)713,079,518		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	11,537,022	11,537,022		
7	Other Clearing Accounts	1,591,134	1,591,134		
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	3,906,825	(b)3,906,825		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	730,114,499	730,114,499		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(1,091,309,728)	(c)(1,091,309,728)		
13	Cost of Removal	(93,116,848)	(93,116,848)		
14	Salvage (Credit)	5,324,078	5,324,078		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(1,179,102,498)	(1,179,102,498)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):				
17.2	Net Credit	488,713,421	(d)488,713,421		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	9,124,670,132	9,124,670,132		

Section B. Balances at End of Year According to Functional Classification

20	Steam Production	1,688,575,991	1,688,575,991		
21	Nuclear Production	1,975,988,596	1,975,988,596		
22	Hydraulic Production-Conventional	136,354,751	136,354,751		
23	Hydraulic Production-Pumped Storage	25,762,423	25,762,423		
24	Other Production	897,906,176	897,906,176		
25	Transmission	564,469,965	564,469,965		
26	Distribution	3,503,174,190	3,503,174,190		
27	Regional Transmission and Market Operation				
28	General	332,438,040	332,438,040		
29	TOTAL (Enter Total of lines 20 thru 28)	9,124,670,132	9,124,670,132		

FOOTNOTE DATA

(a) Concept: DepreciationExpenseExcludingAdjustments

\$	696,444,536	Electric depreciation expense per the Income Statement Page 114, Line 6 and Page 336, Line 12
	23,393,587	PISA depreciation deferral
	(6,758,605)	Accrual of decommissioning cost of nuclear power plant credited to Account 182.3
\$	713,079,518	Total Depreciation expense – page 219, line 3

(b) Concept: OtherAccounts

\$	1,707,528	Depreciation on Electric Plant Charged to Gas
	104,242	Depreciation on coal cars charged to Account 151
	2,040,061	Asset Retirement Obligation charged to Account 182.3
	54,994	Depreciation Adjustment for Unitization Correction
\$	3,906,825	Total Other Accounts shown on Page 219, line 8

(c) Concept: BookCostOfRetiredPlant

\$	1,093,755,658	Retirements per Schedule Page 204
	2,445,930	Less: Retirements of intangible property
	—	Less: Retirements of non-depreciable property
\$	1,091,309,728	Total Book Cost of Plant Retired – Page 219, line 12

(d) Concept: OtherAdjustmentsToAccumulatedDepreciation

Electric Plant Transfers

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

- Report below investments in Account 123.1, Investments in Subsidiary Companies.
- Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
- Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
- For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
- If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
- Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
- In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
- Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1	Ameren Missouri Securitization Funding I, LLC (AMF) - Subsidiary Company Subheading	12/06/2024						
2	AMF - Capital Contribution						2,380,605	
3	AMF - Unappropriated Undistributed Subsidiary Earnings				(1,052,747)		(1,052,747)	
42	Total Cost of Account 123.1 \$		Total		(1,052,747)		1,327,858	

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	108,761,859	112,665,704	Electric and Gas
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	(a)329,525,159	(a)337,722,362	Electric and Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	32,966,936	31,646,597	Electric
8	Transmission Plant (Estimated)	3,974,082	1,784,847	Electric
9	Distribution Plant (Estimated)	22,819,517	21,142,014	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	(a)353,857	404,602	Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	389,639,551	392,700,422	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	5,576,329	5,690,246	(d)(e) Electric and Gas
17				
18				
19				
20	TOTAL Materials and Supplies	503,977,739	511,056,372	

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesConstruction

Functionalization of Account 154 Assigned to - Construction - Beginning of Year:

Production	\$	180,712,717
Transmission	\$	21,784,469
Distribution	\$	125,088,261
Gas	\$	1,939,712
	\$	329,525,159

(b) Concept: PlantMaterialsAndOperatingSuppliesConstruction

Functionalization of Account 154 Assigned to - Construction:

Production	\$	194,400,519
Transmission	\$	10,964,062
Distribution	\$	129,872,369
Gas	\$	2,485,412
	\$	337,722,362

(c) Concept: PlantMaterialsAndOperatingSuppliesOther

Applies to line 11, columns (b) and (c):

Other Material and Supplies relates to distribution of gas.

(d) Concept: StoresExpenseUndistributedDepartmentsUsingMaterial

This footnote applies to line 16, column (b):

Functionalization of Account 163 Stores Expense Undistributed - Beginning of Year:

Production	\$	3,058,078
Transmission	\$	368,644
Distribution	\$	2,116,783
Gas	\$	32,824
	\$	5,576,329

(e) Concept: StoresExpenseUndistributedDepartmentsUsingMaterial

This footnote applies to line 16, column (c):

Functionalization of Account 163 Stores Expense Undistributed:

Production	\$	3,275,433
Transmission	\$	184,732
Distribution	\$	2,188,205
Gas	\$	41,876
	\$	5,690,246

20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	1,431,222	0	206,667		123,980		123,980		3,347,460		5,233,309	
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year	1,758	0	1,758		1,758		1,758		86,142		93,174	0
37	Add: Withheld by EPA	0	0	0	0	0		0		3,516		3,516	0
38	Deduct: Returned by EPA	0	0	0	0	0		0		0		0	0
39	Cost of Sales	1,758	0	0	0	0		0		1,758		3,516	0
40	Balance-End of Year	0		1,758		1,758		1,758		87,900		93,174	0
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)					0	0	0	0	0	0	0	0
44	Net Sales Proceeds (Other)	1,758	35	0	0	0	0	0	0	1,758	35	3,516	70
45	Gains	1,758	35	0	0	0	0	0	0	1,758	35	3,516	70
46	Losses	0	0	0	0	0	0	0	0	0	0	0	0

20.1	Allowances Used	164	0	0	0	0	0	0	0	0	0	164	0
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	80,320	0	28,895	0	0	0	0	0	0	0	109,215	0
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: AllowancesRelinquishedOtherNumber

EPA Adjustment for allowance conversion.

FERC FORM No. 1 (ED. 12-95)

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1				0		
20	TOTAL					

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	Callaway flood study per NRC 50.54(f) Request for Information Letter Per MoPSC ER-2014-0258, amortization period is as follows (06/2015 to 05/2025)	131,271		407065	92,652	38,619
49	TOTAL	131,271			92,652	38,619

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	Transmission Studies				
2	None				
20	Total				
21	Generation Studies				
22	None				
39	Total				
40	Grand Total				

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	^{(g),(h)} Taxes - Temporary Differences	126,105,449	258,915,034	254, 282	147,929,510	237,090,973
2	Derivative Mark-to-Market Regulatory Asset	24,640,767	14,773,452	244	24,640,767	14,773,452
3	^(c) Proposition C Renewable Energy Costs-Other	1,765,603		419, 431,509	1,215,829	549,774
4	^(d) Proposition C Renewable Energy Costs-Solar Rebates	1,561,718		908	1,337,652	224,066
5	^(e) Bank Credit Facility Fees	2,301,649	2,774	107	575,412	1,729,011
6	^(f) Sioux Scrubber Construction Accounting	17,757,315		407	2,536,764	15,220,551
7	Sioux Scrubber Construction Accounting-Contra Account	(7,919,801)	1,131,396			(6,788,405)
8	^(g) Missouri Energy Efficiency Investment Act (MEEIA)	22,305,694	35,566,847	182.3, 254, 407, 419, 440, 442	33,578,428	24,294,113
9	^(h) Plant In Service Accounting	502,501,344	121,752,527	182.3, 403, 404, 431	21,664,451	602,589,420
10	Plant In Service Accounting-Contra Account	(116,688,293)	5,062,300	182.3, 403, 404, 431	27,375,601	(139,001,594)
11	⁽ⁱ⁾ Renewable Energy Standard Rate Adjustment Mechanism (RESRAM)	49,287,826	48,804,958	182.3, 254, 407, 419, 431	46,639,070	51,453,714
12	Renewable Energy Standard Rate Adjustment Mechanism (RESRAM)-Contra Account	(825,698)	1,576,627	182.3, 254, 407, 419, 431	977,643	(226,714)
13	^(j) OPEB Regulatory Tracker	223,585		926	302,928	(79,343)
14	Pension Regulatory Tracker	28,116		926	38,076	(9,960)
15	^(k) Rider DCA (Delivery Charge Adjustment)	41,312				41,312
16	^(l) Charge Ahead Program	6,152,057	2,609,053	184, 407	904,685	7,856,425
17	^(m) COVID-19 Accounting Authority Order	5,656,727		407, 450, 487	1,786,344	3,870,383

18	COVID-19 Accounting Authority Order-Contra Account	(2,516,250)	794,616			(1,721,634)
19	^(g) PAYS Program Spend Deferral	1,771,934	289,715	908	125,627	1,936,022
20	^(g) Equity Issuance Costs Regulatory Deferral	6,535,190		407	255,444	6,279,746
21	Equity Issuance Costs Regulatory Deferral-Contra Account	(6,535,190)	255,444			(6,279,746)
22	^(g) Meramec Retirement Regulatory Asset	38,581,455		407	12,183,619	26,397,836
23	^(g) Under Recovery of Regulatory Amortization Non-Rate Base		3,438,525			3,438,525
24	Under Recovery of Regulatory Amortization Rate Base	97,098		407	53,712	43,386
25	⁽ⁱ⁾ Advanced Meter Infrastructure (AMI) Software - Gas Deferral	1,480,107		182,3, 404, 431	306,229	1,173,878
26	AMI Software Gas Deferral-Contra Account	(45,975)	9,512			(36,463)
27	^(s) Rider WNA (Weather Normalization Adjustment)	3,989,812	4,745,970	419, 480	3,075,503	5,660,279
28	^(t) Property Tax Tracker	12,815,342	12,732,245	408	3,514,614	22,032,973
29	^(u) Meramec Obsolete Inventory	7,868,303		407	1,064,224	6,804,079
30	^(v) Customer Affordability Study	9,798,504		407	2,177,445	7,621,059
31	^(w) Energy Efficiency Rebate Costs		59,442	426, 930	39,000	20,442
32	^(x) Meramec Coal Inventory Adjustment Regulatory Asset		350,276	151, 232	40,139	310,137
33	^(y) Under Collection of Regulatory Amortization		24,250		7	24,243
34	^(z) Securitized Utility Tariff Rider (SUR)		57,500			57,500
35	^(aa) Securitization Adjustment Regulatory Asset		493,809			493,809
36	^(ab) Callaway Post Operational Costs	3,072,864	26	407	3,072,890	
37	^(ac) Callaway Nuclear License Extension	2,161,330		407	103,872	2,057,458
44	TOTAL	713,969,894	513,446,298		337,515,485	889,900,707

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets			
Applies to Page 232:			
For balances with amortization amounts determined in a regulatory rate review, the monthly amortization amounts, calculated based on a specified amortization period, will continue to be recorded at the end of the specified amortization period until completion of the next regulatory rate review in accordance with Missouri Public Service Commission Cases ER-2022-0337 and GR-2021-0241. The net under or over recovery associated with continuing amortizations will be considered during a future regulatory rate review.			
(b) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets			
Offset to certain deferred tax liabilities for the probable recovery through future customer rates of tax benefits related to the equity component of allowance for funds used during construction and the effects of the tax rate changes from the Tax Cuts and Jobs Act. Amounts associated with the equity component of allowance for funds used during construction are being amortized over the expected life of the related assets. The amortization periods for federal electric and gas balances are 10 years for certain balances and the expected life of the related assets for certain plant-related balances. Amortization began in August 2018 for federal electric balances and January 2019 for federal gas balances associated with the effects of the Tax Cut and Jobs Act in accordance with Missouri Public Service Commission Case ER-2018-0362 and GR-2019-0077, respectively. The amortization period for state electric balances is 5 years. Amortization began in April 2020 for state electric balances in accordance with Missouri Public Service Commission Case ER-2019-0335.			
(c) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets			
Established per Missouri Public Service Commission Case ER-2011-0028.			
The sixth accumulation period will be amortized over 3 years beginning July 2023, per MoPSC Case ER-2022-0337.			
(d) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets			
Established per Missouri Public Service Commission Case ER-2011-0028, which was rebased in Case ER-2019-0335, and includes a 10% adder according to the terms of a Missouri Public Service Commission approved agreement.			
The fourth accumulation period is being amortized over 3 years beginning March 2022, per MoPSC Case ER-2021-0240.			
(e) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets			
Established per Missouri Public Service Commission Case ER-2010-0036.			
The balance is being amortized through November 2027.			
(f) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets			
The following footnote relates to the Sioux Scrubber Construction Accounting and its Contra Account.			
Established per Missouri Public Service Commission Case ER-2010-0036. Amortization period of 90 months starting July 2023 per MoPSC Case ER-2022-0337.			
Contra account represents the allowance for equity funds used during construction (AFUDC - equity).			
(g) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets			
Established per Missouri Public Service Commission Case EO-2012-0142.			
MEEIA plan year runs February through January. Amounts will be accumulated during that period and amortized starting in February of the following year.			
The MEEIA regulatory asset balances are comprised entirely of the MEEIA-Performance Incentive.			
(h) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets			
The following footnote relates to Plant In Service Accounting and its Contra Account. Pursuant to Section 393.1400 Revised Statutes of Missouri, elected in MoPSC Case EO-2019-0044. Each accumulation period is amortized over 20 years.			
The contra account represents the cost of equity on PISA deferrals.			
The following amounts relate to the regulatory asset balances per column (f):			
Docket Number	Amortization Starting Period	Gross Regulatory Asset Balance	Contra Asset Balance
ER-2019-0335	April 2020	\$39,234,559	\$(8,221,799)
ER-2021-0240	March 2022	\$170,814,803	\$(38,705,671)
ER-2022-0337	July 2023	\$167,354,182	\$(41,035,351)
TBD ^(a)	TBD ^(a)	\$225,185,876	\$(51,038,773)
Total		\$602,589,420	\$(139,001,594)
(a) Accumulated amounts after December 31, 2022 will be considered in a future rate review.			
(i) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets			
The following footnote relates to RESRAM and its Contra Account.			
Established per Missouri Public Service Commission Case EA-2018-0202.			
Costs incurred over a 12 month period ending July of each year are amortized over the 12 month period beginning February of the following year. The contra account represents the equity component of the return on eligible plant assets.			
(j) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets			
The following footnote relates to OPEB Regulatory Tracker and Pension Regulatory Tracker.			

<p>Established per Missouri Public Service Commission Case GR-2019-0077. Per MoPSC Case GR-2021-0241, the amortization period is 3 years, beginning March 2022.</p>
<p>(k) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets</p>
<p>Established per Missouri Public Service Commission Case GR-2019-0077.</p> <p>Per MoPSC Case GR-2021-0241, Rider DCA transitioned to Rider WNA for residential customers and the final DCA balance for other customer classes will be considered in a future rate review.</p>
<p>(l) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets</p>
<p>Charge Ahead Corridor was established per Missouri Public Service Commission Case ET-2018-0132.</p> <p>The first accumulation period is being amortized over 7 years beginning March 2022, per MoPSC Case ER-2021-0240. The second accumulation period is being amortized over 7 years beginning July 2023, per MoPSC Case ER-2022-0337.</p> <p>Charge Ahead Off-Road Electrification Program was established per Missouri Public Service Commission Case ET-2021-0020. Per MoPSC Case ER-2022-0337, amortization period is 7 years beginning July 2023.</p>
<p>(m) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets</p>
<p>The following footnote relates to the COVID-19 Accounting Authority Order and its Contra Account.</p> <p>Established per Accounting Authority Orders EU-2021-0027 and GU-2021-0112. Per MoPSC Case ER-2021-0240 and GR-2021-0241, amortization period will be 5 years beginning March 2022.</p>
<p>(n) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets</p>
<p>Established per Missouri Public Service Commission Case EO-2018-0211.</p> <p>The costs associated with energy efficiency projects under the Pay As You Save (PAYS) program are deferred and earn a return. Participating customers begin receiving charges for a portion of project costs 45 days after project completion, and related deferred costs begin amortizing over the payment term of the agreement.</p> <p>An amortization period of 137 months beginning March 2022 for remaining costs, not recovered from program participants, was established per MoPSC Case ER-2021-0240. An amortization period of 139 months beginning July 2023 for remaining costs, not recovered from program participants in the second accumulation period was established per MoPSC Case ER-2022-0337.</p>
<p>(o) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets</p>
<p>The following footnote is related to the Equity Issuance Costs Regulatory Deferral and its Contra Account.</p> <p>Established per MoPSC Case ER-2021-0240, equity issuance costs associated with raising capital for renewable energy generation is being recovered over a period of 329 months beginning March 2022.</p>
<p>(p) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets</p>
<p>Established per MoPSC Case ER-2021-0240.</p> <p>Costs associated with the 10 months of operation of Ameren Missouri's Meramec Energy Center from March 1, 2022 to December 31, 2022 are being recovered over a period of 5 years beginning in March 2022.</p>
<p>(q) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets</p>
<p>The following footnote is related to the Under Recovery of Regulatory Amortization Non-Rate Base and Under Recovery of Regulatory Amortization Rate Base regulatory assets.</p> <p>Established per MoPSC Case ER-2014-0258 and subsequently rebased in MoPSC Case ER-2022-0337.</p> <p>Amortization period of 3 years beginning in July 2023.</p>
<p>(r) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets</p>
<p>The following footnote is related to the AMI software gas-related amortization deferral and its Contra Account.</p> <p>Established per MoPSC Case GR-2021-0241, deferrals to be amortized over the life of the related software.</p>
<p>(s) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets</p>
<p>Established per MoPSC Case GR-2021-0241.</p> <p>The accumulation periods run August through July of each year with annual billings commencing each November for 12 consecutive months.</p>
<p>(t) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets</p>
<p>Established pursuant to Section 393.1275 Revised Statutes of Missouri.</p> <p>Per MoPSC Case ER-2022-0337, costs accumulated during the first accumulation period between September 2022 and December 2022 are being amortized over 2 years beginning July 2023. An amortization period for costs accumulated after December 2022 will be determined in a future rate review.</p>
<p>(u) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets</p>
<p>Established per MoPSC Case ER-2022-0337.</p> <p>Costs associated with obsolete inventory as a result of the closure of the Meramec Energy Center on December 31, 2022. Costs incurred through December 31, 2022 are being recovered over a period of 5 years beginning July 2023. An amortization period for costs incurred after December 31, 2022 will be determined in a future rate review.</p>
<p>(v) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets</p>
<p>Established per MoPSC Case ER-2022-0337.</p> <p>Costs associated with customer affordability study performed in 2022. Costs are being recovered over a period of 5 years beginning July 2023.</p>
<p>(w) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets</p>
<p>Established per Missouri Public Service Commission Case EE-2021-0086.</p> <p>The following footnote relates to energy efficiency rebate costs for certain residential customers. An amortization period will be established in a future rate review.</p>

(x) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

The following footnote is related to final fuel inventory amounts at the recently closed Meramec Energy Center. An amortization period will be established in a future rate review.

(y) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

The following footnote is related to the Under Collection of Regulatory Amortization regulatory assets.

Established per MoPSC Case GR-2019-0077 and subsequently rebased in MoPSC Case GR-2021-0241. Amortization period of 3 years beginning in March 2022.

(z) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Established per MoPSC Case EF-2024-0021.

The accumulation periods typically last for 6 months, followed by a 6 month amortization period.

(aa) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Established per MoPSC Case EF-2024-0021.

Additional costs related to securitization beyond those included in the order. An amortization period will be established in a future rate review.

(ab) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Established per Missouri Public Service Commission Case FA86-55-000 Opinion 354.

Amortization period over remaining life of the plant's original operating license through October 2024.

(ac) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Established per Missouri Public Service Commission Case ER-2014-0258.

The first accumulation period is being amortized over a period of 331 months starting April 2017 per MoPSC Case ER-2016-0179, which established the second accumulation period. In accordance with MoPSC Case ER-2019-0335, the second accumulation period is being amortized over the remaining term of the first accumulation period beginning in April 2020.

FERC FORM No. 1 (REV. 02-04)

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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MISCELLANEOUS DEFERRED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than \$100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	IBNR Workers Compensation	4,000,000				4,000,000
2	Discount Commercial Paper	118,794	32,629,240	231	32,748,034	
3	Accenture Service Credits	1,892,693		588	22,500	1,870,193
4	Credit Facility Extension Fee		399,269			399,269
5	Minor Items	1,093	2,740	107, 131, 566	42,786	(38,953)
47	Miscellaneous Work in Progress	(36,114)				1,429,099
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	5,976,466				7,659,608

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ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	ADIT Unamortized Investment Tax Credit	7,927,978	56,599,930
3	Non-property temporary differences	219,426,240	452,643,612
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	227,354,218	509,243,542
9	Gas		
10	ADIT Unamortized Investment Tax Credit	9,286	4,194
11	Non-property temporary differences	5,407,138	5,647,133
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	5,416,424	5,651,327
17.1	Other - Steam		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	232,770,642	514,894,869

Notes

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

		Beginning of Year
Total Electric Account 190		\$ 227,354,218
Plus: Tax Rate Changes		3,287,734
Less: Unamortized Investment Tax Credit		7,927,978
Subtotal		\$ 222,713,974
Temporary Differences Excluded from State jurisdictional rates		169,137,932
		\$ 53,576,042
Functionalization of Account 190, beginning of year		
Production	51.16 %	
Transmission	6.26 %	
Distribution	30.17 %	
General	12.41 %	

(b) Concept: AccumulatedDeferredIncomeTaxes

		End of Year
Total Electric Account 190		\$ 509,243,542
Plus: Tax Rate Changes		2,500,265
Less: Unamortized Investment Tax Credit		56,599,930
subtotal		\$ 455,143,877
Temporary differences excluded from State jurisdictional rates		414,338,983
		\$ 40,804,894
Functionalization of Account 190, end of year		
Production	45.92 %	
Transmission	8.35 %	
Distribution	34.13 %	
General	11.60 %	

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CAPITAL STOCKS (Account 201 and 204)

- Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
- Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
- Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
- The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
- State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
- Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	Common Stock, \$5.00 par value +	150,000,000	5.00		102,123,834	510,619,170				
7	Total	150,000,000			102,123,834	510,619,170				
8	Preferred Stock (Account 204)									
9	\$4.56 SERIES - New York Stock Exchange		100.00	102.47	200,000	20,000,000				
10	\$4.50 SERIES - New York Stock Exchange		100.00	110.00	213,595	21,359,500				
11	\$4.00 SERIES - New York Stock Exchange		100.00	105.63	150,000	15,000,000				
12	\$3.70 SERIES - Not Registered		100.00	104.75	40,000	4,000,000				

13	\$3.50 SERIES - New York Stock Exchange		100.00	110.00	130,000	13,000,000				
14	\$4.75 SERIES - Not Registered		100.00	102.18	20,000	2,000,000				
15	\$4.30 SERIES - Not Registered		100.00	105.00	40,000	4,000,000				
16	\$5.50 SERIES A - Not Registered		100.00	110.00	14,000	1,400,000				
17	Total Preferred Stock	25,000,000								
60	Total	25,000,000			807,595	80,759,500				

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2025-04-08	Year/Period of Report End of: 2024/ Q4
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Other Paid-in Capital

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Donations Received from Stockholders (Account 208)	
2	Beginning Balance Amount	3,461,890
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	3,461,890
5	Reduction in Par or Stated Value of Capital Stock (Account 209)	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)	
10	Beginning Balance Amount	854,990
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	854,990
13	Miscellaneous Paid-In Capital (Account 211)	
14	Beginning Balance Amount	2,008,470,550
15.1	Increases (Decreases) in Miscellaneous Paid-In Capital	475,756,701
16	Ending Balance Amount	2,484,227,251
17	Other Paid in Capital	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	2,488,544,131

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
5		
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11		
12		
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14		
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16		
17		
18		
19		
20		
21		
22	TOTAL	

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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LONG-TERM DEBT (Account 221, 222, 223 and 224)

- Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Term Debt.
- For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (l)
- For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such companies from which advances were received, and in column (b) include the related account number.
- For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column
- In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
- If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of
- If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities
- If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (l) total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
- Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)
1	Bonds (Account 221)									
2	5.50% due 2034	221-105	184,000,000		2,135,951		2,055,280	03/10/2003	03/15/2034	03/10/2003
3	5.30% due 2037	221-112	300,000,000		2,980,534		1,017,000	07/21/2005	08/01/2037	08/01/2005
4	8.45% due 2039	221-117	350,000,000		3,473,842		1,165,500	03/20/2009	03/15/2039	03/01/2009
5	3.90% due 2042	221-118	485,000,000		4,829,638		2,551,100	09/11/2012	09/15/2042	09/15/2012
6	3.50% due 2024	221-119	350,000,000		2,891,722		63,000	04/04/2014	04/15/2024	04/04/2014
7	3.65% due 2045	221-121	400,000,000		4,493,346		1,322,091	04/06/2015	04/15/2045	04/06/2015
8	2.95% due 2027	221-122	400,000,000		3,358,057		1,304,000	06/15/2017	06/15/2027	06/15/2017
9	4.00% due 2048	221-123	425,000,000		4,526,648		1,840,250	04/06/2018	04/01/2048	04/06/2018
10	3.50% due 2029	221-124	450,000,000		4,384,911		382,500	03/06/2019	03/15/2029	03/06/2019
11	3.25% due 2049	221-125	330,000,000		3,238,520		1,040,244	10/01/2019	10/01/2049	10/01/2019
12	2.95% due 2030	221-126	465,000,000		3,906,788		399,900	03/20/2020	03/15/2030	03/20/2020
13	2.625% due 2051	221-127	550,000,000		5,672,744		2,612,195	10/09/2020	03/15/2051	10/09/2020

14	2.15% - Missouri Public Service Commission EF-2021-0176 dated 4/28/21	221-128	525,000,000		4,499,136		572,250	06/22/2021	03/15/2032	06/22/2021
15	3.90% - Missouri Public Service Commission EF-2022-0164 dated 3/9/22	221-130	525,000,000		5,457,611		1,259,861	04/01/2022	04/01/2052	04/01/2022
16	5.45% - Missouri Public Service Commission EF-2023-0151 dated 2/16/23	221-131	500,000,000		5,416,657		1,030,000	03/13/2023	03/15/2053	03/13/2023
17	2.90% due 2033 - Series A	221-09A	60,000,000		659,670			07/03/2019	09/01/2033	07/03/2019
18	2.90% due 2033 - Series B	221-09B	50,000,000		554,322			07/10/2019	09/01/2033	07/10/2019
19	2.75% due 2033	221-09C	50,000,000		554,480			06/12/2019	09/01/2033	06/12/2019
20	5.25% due 2054	221-132	350,000,000		3,883,010		2,565,500	01/09/2024	01/15/2054	01/09/2024
21	5.20% due 2034	221-133	500,000,000		4,257,973		1,575,000	04/04/2024	04/01/2034	04/04/2024
22	5.125% due 2055	221-135	450,000,000		4,391,879		535,500	10/07/2024	03/15/2055	10/07/2024
23	Subtotal		7,699,000,000		75,567,439		23,291,171			
24	Reacquired Bonds (Account 222)									
25										
26										
27										
28	Subtotal									
29	Advances from Associated Companies (Account 223)									
30	3.65% Due 04/15/2045	223-121	7,032,000		55,389		16,409	04/06/2015	04/15/2045	04/06/2015
31	3.25% Due 10/01/2049	223-125	32,257,000		285,565		91,656	10/01/2019	10/01/2049	10/01/2019
32	2.625% Due 03/15/2051	223-127	4,070,000		36,521		16,805	10/09/2020	03/15/2051	10/09/2020
33	3.90% Due 04/01/2052	223-130	14,116,000		138,169		31,639	04/01/2022	04/01/2052	04/01/2022
34	Subtotal		57,475,000		515,644		156,509			

35	Other Long Term Debt (Account 224)									
36										
37										
38										
39	Subtotal									
33	TOTAL		7,756,475,000							

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FOOTNOTE DATA

(a) Concept: NominalDateOfIssue

This footnote applies to line 7, columns (h) and (j).

Original issuance date for the \$250,000,000 of 3.65% Senior Secured Notes due 2045 was 4/6/2015. On 6/23/2016, an additional \$150,000,000 of 3.65% Senior Secured Notes due 2045 were issued. This new issuance was a further issuance of the 3.65% Senior Secured Notes due 2045 issued in the amount of \$250,000,000 in April 2015. The new bonds have the identical coupon rate, coupon payment dates and maturity date as the bonds issued in April 2015. The new issuance increases the total principal amount outstanding of this series to \$400,000,000.

The amortization periods for the debt expenses and the debt discount for the 4/6/2015 issuance began on that issuance date. The amortization period of the 6/23/2016 issuance began as of its issuance. The amortization end date for both issuances is the same.

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RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	562,303,136
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Medicare Part D	666,000
6	Total	666,000
9	Deductions Recorded on Books Not Deducted for Return	
10	Federal Income Tax	(a)41,814,008
11	Other	(a)209,851,348
12	Subsidiary Earnings	1,052,747
13	Total	252,718,103
14	Income Recorded on Books Not Included in Return	
15	Book Adjustment	
16	Deferred Income Taxes including Amortization of Investment Tax Credit	143,108,237
17	Total	143,108,237
19	Deductions on Return Not Charged Against Book Income	
20	Plant Temporary Differences	68,198,449
21	Other	(a)192,844,423
22	Total	261,042,872
27	Federal Tax Net Income	411,536,130
28	Show Computation of Tax:	
29	Federal Income Tax	(86,422,587)
30	Adjustments	44,608,579
31	Total Federal Income Tax Payable	(41,814,008)

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FOOTNOTE DATA

(a) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

The consolidated tax is allocated to each member of the consolidated tax group using a stand-alone calculation ratio to the total amount of tax owed by the consolidated group.

Ameren Accelerator Investments, LLC	(11,686)
Ameren Development Company	1,182,852
Ameren EIP Investment, LLC	(90,272)
Ameren Illinois Company	5,383,220
Ameren Corporation	(7,761,472)
Ameren Services Company	(7,397,978)
ATX TIP Holdings Inc	—
ATX East, LLC	(4,988)
ATX Southwest, LLC	(19,565)
Ameren Transmission Company, LLC	(383,417)
Ameren Transmission Company of Illinois	18,205,975
Elimination Consolidation Entity	3,155,065
Lucky Corridor, LLC	(58,984)
Mutual Business Program 39	184,089
Ameren Missouri Securitization Funding I LLC	(96,507,122)
AmerenEnergy Medina Valley CoGen, LLC	(254,466)
QST Enterprises, Inc.	9,295
Union Electric Company	41,814,008
Total	<u>(42,555,446)</u>

(b) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

Deductions Recorded on Books Not Deducted for Return

Entertainment Expense	\$ 30,388
Disallowance of Meals	701,526
Non-Deductible Employee Parking Expense	459,879
Non-Deductible Transit Passes	6,903
Lobbying Expenses	1,572,934
Penalties	2,021,593
Asset Retirement Obligation Liability	10,375,240
Active Voluntary Employee Beneficiary Association VEBA Plan	310,370
Change in Injury and Damages	1,893,140
Legal Expense Reserve	2,404,454
Employee Bonus Accrual	2,010,870
Leased Liabilities	57,888,548
Over/Under Accrual of Franchise Taxes	2,392,110
Over/Under Accrual of Property Taxes	291,794
Book Loss on Reacquired Debt	2,569,104
Deferred Intercompany Tax Gain- Metro	1,636,080
Fuel Adjustment Clause	31,609,249
Callaway Deferral Mechanism	24,203,312
Manufactured Gas Clean Up	875,000
Sioux Scrubber Construction Accounting	1,405,368
Bank Credit Facilities	572,636
Test Storm Cost and Other Regulatory Assets	64,620,850
	<u>\$ 209,851,348</u>

(c) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

Deductions on Return Not Charged Against Book Income

Preferred Dividend Paid Credit	\$	692,120
Change in Uncollectible Accounts		585,423
Change in Obsolete Inventory		1,273,591
Charitable Contributions		1,651,919
Contingent Liabilities		12,269,344
Book/Tax (Other Postretirement Employee Benefits)		24,563,348
Gas Storage Fields		195,235
Low Level Nuclear Waste		15,000
Over/Under Accrual of State Income Tax		38,000
Pension Expense Allowed/Disallowed		34,325,285
Pension/OPEB Tracker		40,314,019
Efficiency Regulatory Asset		3,074,244
Excess Tracker		15,551,368
Leased Assets		57,586,686
Prepaid Insurance		339,611
Purchase Gas Adjustment		148,491
State Income Tax Adjustment		220,739
	\$	<u>192,844,423</u>

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TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. If the actual, or estimated amounts of such taxes are known, show the amounts in the accounts to which the taxed material was charged.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) taxes accrued and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the tax year.
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments with a minus sign and credit adjustments with a plus sign.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmission to the taxing authority.
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the tax year.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)
1	Federal	Federal Tax		2024	0	0	41,814,008	(131,308,054)	(173,122,062) ^(b)	
2					0	0				
3	Subtotal Federal Tax				0	0	41,814,008	(131,308,054)	(173,122,062)	
4	Arkansas	Income Tax	Arkansas	2024	0	0	(9,000)		9,000 ^(b)	
5	Illinois	Income Tax	Illinois	2024	0	0	(46,529)	246,089	292,618 ^(a)	
6	Indiana	Income Tax	Indiana	2024	0	0	148,933		(148,933) ^(a)	
7	Iowa	Income Tax	Iowa	2024	0	0	167,750		(167,750) ^(b)	
8	Michigan	Income Tax	Michigan	2024	0	0				
9	Missouri	Income Tax	Missouri	2024	0	0	13,717,223	(5,211,779)	(18,929,002) ^(a)	
10	Oklahoma	Income Tax	Oklahoma	2024	0	0	7,500	7,500		
11	Subtotal State Tax				0	0	13,985,877	(4,958,190)	(18,944,067)	
12	St. Louis City	Local Tax		2024	0	0	(25,360)	60,000	85,360 ^(b)	
13	Subtotal Local Tax				0	0	(25,360)	60,000	85,360	
14	Subtotal Other Tax				0	0	0	0	0	
15	AR Personal Property	Property Tax	Arkansas	2024	0	0	92	92		
16	CO Personal Property	Property Tax	Colorado	2024	0	0				
17	IL Real Estate	Property Tax	Illinois	2023	4,160,000	0	117,992	4,277,992		

18	IL Real Estate	Property Tax	Illinois	2024	0	0	4,245,000			4,245,0
19	IA Real & Personal Property	Property Tax	Iowa	2024	0	0	1,279,212	1,279,212		
20	KS Personal Property	Property Tax	Kansas	2024	0	0	243,398	243,398		
21	MS Personal Property	Property Tax	Mississippi	2024	0	0				
22	MO Real & Personal Property	Property Tax	Missouri	2023	0	0	(326,201)	(326,201)		
23	MO Real & Personal Property	Property Tax	Missouri	2024	0	0	195,991,785	195,991,785		
24	OK Personal Property	Property Tax	Oklahoma	2024	0	0	5,339	5,339		
25	WV Personal Property	Property Tax	West Virginia	2024	0	0	3,809	3,809		
26	WY Personal Property	Property Tax	Wyoming	2024	0	0	10,359	10,359		
27	Subtotal Property Tax				4,160,000	0	201,570,785	201,485,785	0	4,245,0
28	Subtotal Real Estate Tax				0	0	0	0	0	
29	Federal Unemployment	Unemployment Tax		2023	0	0				
30	Federal Unemployment	Unemployment Tax		2024	0	0	178,360	178,360		
31	Arizona Unemployment	Unemployment Tax	Arizona	2024	0	0	319	319		
32	Colorado Unemployment	Unemployment Tax	Colorado	2024	0	0	656	656		
33	Georgia Unemployment	Unemployment Tax	Georgia	2024	0	0	4	4		
34	Iowa Unemployment	Unemployment Tax	Iowa	2024	0	0	5,978	5,978		
35	Illinois Unemployment	Unemployment Tax	Illinois	2024	0	0	22,649	22,649		
36	Missouri Unemployment	Unemployment Tax	Missouri	2024	0	0				
37	North Carolina Unemployment	Unemployment Tax	North Carolina	2024	0	0	314	314		
38	Ohio Unemployment	Unemployment Tax	Ohio	2024	0	0	243	243		
39	Pennsylvania Unemployment	Unemployment Tax	Pennsylvania	2024	0	0	175	175		
40	Texas	Unemployment Tax	Texas	2024	0	0	22	22		
41	Virginia	Unemployment Tax	Virginia	2024	0	0	200	200		

42	Subtotal Unemployment Tax				0	0	208,920	208,920	0	
43	Subtotal Sales And Use Tax				0	0	0	0	0	
44	Subtotal Income Tax				0	0				
45	Federal Excise	Excise Tax		2024	0	0	66,667	66,667		
46	MO Gross Receipts-Unbilled	Excise Tax	Missouri	2024	8,776,527	0	200,704			8,977,2
47	MO Municipal	Excise Tax	Missouri	2023	11,688,404	0	(133,326)	11,555,078		
48	MO Municipal	Excise Tax	Missouri	2024	0	0	169,092,895	157,352,715		11,740,1
49	Subtotal Excise Tax				20,464,931	0	169,226,940	168,974,460	0	20,717,4
50	Subtotal Fuel Tax				0	0	0	0	0	
51	Subtotal Federal Insurance Tax				0	0	0	0	0	
52	Corporate Franchise	Franchise Tax	Illinois	2024	0	0	87,651	87,651		
53	Corporate Franchise	Franchise Tax	Oklahoma	2023	0	0	3,343	3,343		
54	Subtotal Franchise Tax				0	0	90,994	90,994	0	
55	Insurance Premium Tax	Miscellaneous Other Tax	Missouri	2023	277,120	0	12,697	289,817		
56	Insurance Premium Tax	Miscellaneous Other Tax	Missouri	2024	0	0	251,000			251,0
57	Commercial Activity Tax	Miscellaneous Other Tax	Ohio	2024	0	0				
58	Subtotal Miscellaneous Other Tax				277,120	0	263,697	289,817	0	251,0
59	Subtotal Other Federal Tax				0	0	0	0	0	
60	Subtotal Other State Tax				0	0	0	0	0	
61	Subtotal Other Property Tax				0	0	0	0	0	
62	Subtotal Other Use Tax				0	0	0	0	0	
63	Subtotal Other Advalorem Tax				0	0	0	0	0	
64	Subtotal Other License And Fees Tax				0	0	0	0	0	
65	Social Security & Medicare	Payroll Tax		2022	0	0				
66	Social Security & Medicare	Payroll Tax		2023	2,815,061	0		2,815,061		

67	Social Security & Medicare	Payroll Tax		2024	0	0	40,448,228	36,388,459		4,059,7
68	St. Louis	Payroll Tax		2024	0	0	349,052	349,052		
69	Subtotal Payroll Tax				2,815,061	0	40,797,280	39,552,572	0	4,059,7
70	Subtotal Advalorem Tax				0	0	0	0	0	
71	Subtotal Other Allocated Tax				0	0	0	0	0	
72	Subtotal Severance Tax				0	0	0	0	0	
73	Subtotal Penalty Tax				0	0	0	0	0	
74	Subtotal Other Taxes And Fees				0	0	0	0	0	
40	TOTAL				27,717,112	0	467,933,141	274,396,304	(191,980,769)	29,273,1

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FOOTNOTE DATA

(a) Concept: TaxesAccrued

Kind of Tax (a)	Taxes Accrued (e)	Prepaid Taxes (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	Taxes Accrued (j)	Electric (l)	Other (o)
Federal Taxes	2,815,061	0	82,507,263	(91,859,507)	(173,122,062)	4,059,769	72,775,843	9,731,420
Arizona Taxes	0	0	319	319	0	0	319	0
Arkansas Taxes	0	0	(8,908)	92	9,000	0	(8,908)	0
Colorado Taxes	0	0	656	656	0	0	656	0
Georgia Taxes	0	0	4	4	0	0	4	0
Illinois Taxes	4,160,000	0	4,426,763	4,634,381	292,618	4,245,000	4,426,763	0
Indiana Taxes	—	0	148,933	—	(148,933)	—	183,822	(34,889)
Iowa Taxes	—	0	1,452,940	1,285,190	(167,750)	—	1,489,849	(36,909)
Kansas Taxes	—	0	243,398	243,398	—	—	—	243,398
Michigan Taxes	0	0	0	0	0	0	0	0
Mississippi Taxes	0	0	—	—	0	0	—	—
Missouri Municipal	20,464,931	0	169,160,273	168,907,793	0	20,717,411	162,060,077	7,100,196
Missouri Taxes	277,120	0	209,646,504	190,743,622	(18,929,002)	251,000	181,937,734	27,708,770
Ohio Taxes	—	0	243	243	0	—	243	—
Oklahoma Taxes	—	0	16,182	16,182	—	—	—	16,182
North Carolina Taxes	0	0	314	314	0	0	314	0
Pennsylvania Taxes	0	0	175	175	0	0	175	—
St. Louis Taxes	0	0	323,692	409,052	85,360	0	323,692	0
Texas Taxes	0	0	22	22	—	0	22	0
Virginia Taxes	0	0	200	200	0	0	200	—
West Virginia Taxes	0	0	3,809	3,809	0	0	0	3,809
Wyoming Taxes	0	0	10,359	10,359	0	0	10,359	0
Total	27,717,112	0	467,933,141	274,396,304	(191,980,769)	29,273,180	423,201,164	44,731,977

(b) Concept: TaxAdjustments

	<u>Contra Account</u>	<u>Amount</u>
Income Tax Payable - PY	234	(47,267,380)
Income Tax Receivable - CY	146	21,803,695
Income Tax Payable - CY	234	(96,507,122)
Taxes Payable Reclass	190	(3,651,255)
Taxes Payable Reclass	255	(47,500,000)
Total		(173,122,062)

(c) Concept: TaxAdjustments

	<u>Contra Account</u>	<u>Amount</u>
Income Tax Receivable	146	9,000

(d) Concept: TaxAdjustments

	<u>Contra Account</u>	<u>Amount</u>
Income Tax Receivable	146	292,618

(e) Concept: TaxAdjustments

	<u>Contra Account</u>	<u>Amount</u>
Income Tax Payable	234	(148,933)

(f) Concept: TaxAdjustments

	<u>Contra Account</u>	<u>Amount</u>
Income Tax Payable	234	(167,750)

(g) Concept: TaxAdjustments

	<u>Contra Account</u>	<u>Amount</u>
Income Tax Payable - PY	234	(8,278,168)
Income Tax Payable - CY	234	(10,650,834)
Total		(18,929,002)

(h) Concept: TaxAdjustments

	<u>Contra Account</u>	<u>Amount</u>
Income Tax Receivable	146	85,360

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%									
4	7%									
5	10%	6,946,960			411.4	2,643,474		4,303,486	43 years	
6	30%	18,786,225	190/236	207,027,597	411.4	119,283		225,694,539	43 years	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	25,733,185 ^(a)		207,027,597		2,762,757		229,998,025 ^(b)		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										
11	10%	30,141			411.4	16,623		13,518	40 years	
12	Gas Utility									
13	TOTAL	30,141				16,623		13,518		
47	OTHER TOTAL									
48	GRAND TOTAL	25,763,326		207,027,597		2,779,380		230,011,543		

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredInvestmentTaxCredits	
Functionalization of Total Electric Balance, Beginning of Year	
Production	44.88 %
Transmission	11.40 %
Distribution	37.35 %
General	6.37 %
(b) Concept: AccumulatedDeferredInvestmentTaxCredits	
Functionalization of Total Electric Balance, End of Year	
Production	43.13 %
Transmission	11.89 %
Distribution	38.52 %
General	6.46 %

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than \$100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Clean-up of Contaminated Facilities - Non-Current	1,375,000	232, 184	2,629,704	3,504,704	2,250,000
2	Deferred Compensation - Executive Staff - Non-Current		234	1,603,147	1,603,147	
3	Construction Deposit	647,297	107, 142, 584	15,723	94,718	726,292
4	Bill Back Jobs Prepayments	130,000	107, 186	190,000	417,462	357,462
5	FERC Return on Common Equity Complaint Case	1,856,452			1,027,540	2,883,992
6	Contingent Liability for Generation Construction Project	2,847,415				2,847,415
7	CIAC - Blue Bird Solar	683,959	107	525,234	13,760	172,485
8	CIAC - National Geospatial Intelligence Agency	2,731,587				2,731,587
9	CIAC - Winfield Solar	(61,996)	107	1,165,350	1,716,498	489,152
10	CIAC - Montgomery Solar	342,995	107	3,716		339,279
11	CIAC - Lutesville Solar	533,338	107	101,396	118,432	550,374
12	CIAC - Kelso Solar	429,730	107	447,501	160,246	142,475
13	CIAC - Guthrie Solar	79,306	107	73,994		5,312
14	CIAC - Show Me State Solar	606,701	107	727,379	64,958	(55,720)
15	CIAC - Huck Finn	794,297	107, 566	1,166,621		(372,324)
16	CIAC - Hannibal	15,633	107, 143	15,633		
17	CIAC - Split Rail Solar	538,021	107	182,798	363,000	718,223
18	CIAC - Firebrick Wind	1,057,697	107	688,707		368,990
19	CIAC - Wolf Creek Solar	1,319,000	107	52,100		1,266,900
20	CIAC - Kelso 2 Solar	603,000	107, 232	72,169		530,831
21	CIAC - Navier	600,000	107	125,562		474,438
22	CIAC - Ringer Solar Energy		107	7,161	331,000	323,839
23	CIAC - Grain Belt Express		107, 421	668,476	14,415,300	13,746,824
24	CIAC - Hannibal Joint Operating Agreement		143, 421	598,057	598,057	
25	Minor item			1	64	63

47	TOTAL	17,129,432		11,060,429	24,428,886	30,497,889
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16.2	Other										
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	77,330,585	12,947,272	37,188,904							53,088,953
18	Classification of TOTAL										
19	Federal Income Tax	66,466,786	11,230,972	33,160,626							44,537,132
20	State Income Tax	10,863,799	1,716,300	4,028,278							8,551,821
21	Local Income Tax										

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesAcceleratedAmortizationProperty	
Functionalization of Total Electric Balance, beginning of year	
Production	100 %
(b) Concept: AccumulatedDeferredIncomeTaxesAcceleratedAmortizationProperty	
Functionalization of Total Electric Balance, end of year	
Production	100 %

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization.
2. For other (Specify), include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS			
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits	
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)
1	Account 282									
2	Electric	2,049,527,807 ^(b)	276,571,576	332,767,058			182.3, 254	167,737,178	182.3, 254	299,941,318 ²
3	Gas	49,540,346	15,924,582	1,347,738			182.3, 254	1,768,865	182.3, 254	3,807,731
4	Other (Specify)	^(b) (8,001,681)			1,055,588	77,661				
5	Total (Total of lines 2 thru 4)	2,091,066,472	292,496,158	334,114,796	1,055,588	77,661		169,506,043		303,749,049 ²
6										
7										
8										
9	TOTAL Account 282 (Total of Lines 5 thru 8)	2,091,066,472	292,496,158	334,114,796	1,055,588	77,661		169,506,043		303,749,049 ²
10	Classification of TOTAL									
11	Federal Income Tax	1,782,565,081	244,031,440	263,687,834	897,298	58,939		119,385,904		220,453,381 ¹
12	State Income Tax	308,501,391	48,464,718	70,426,962	158,290	18,722		50,120,139		83,295,668
13	Local Income Tax									

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

		Beginning of Year
Electric Account 282		\$ 2,049,527,807
Remove impact of Accounting Standards Codification Topic 740		822,032,360
Subtotal		\$ 2,871,560,167
Remove impact of temporary differences excluded from State		(38,102,180)
		\$ 2,833,457,987
Functionalization of Account 282 excluding temporary differences excluded from rates, beginning of year		
Production	44.88 %	
Transmission	11.40 %	
Distribution	37.35 %	
General	6.37 %	

(b) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

		Beginning of Year
Other Non-Utility Property 282		\$ (8,001,681)
Temporary differences excluded from State jurisdictional rates		(8,001,681)
		\$ —

(c) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

		End of Year
Electric Account 282		\$ 2,125,536,465
Remove impact of Accounting Standards Codification Topic 740		689,828,223
Subtotal		\$ 2,815,364,688
Remove impact of temporary differences excluded from State		(46,033,104)
		\$ 2,769,331,584
Functionalization of Account 282 excluding temporary differences excluded from rates, end of year		
Production	43.13 %	
Transmission	11.89 %	
Distribution	38.52 %	
General	6.46 %	

(d) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

		End of Year
Other Non-Utility Property 282		\$ (7,023,754)
Temporary differences excluded from State jurisdictional rates		(7,023,754)
		\$ —

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify), include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Non-Property Temporary Difference	158,021,949	64,660,725	78,612,427		254	147,809	254	3,360,906		147,283,344
9	TOTAL Electric (Total of lines 3 thru 8)	158,021,949 ^(a)	64,660,725	78,612,427			147,809		3,360,906		147,283,344 ^(b)
10	Gas										
11	Non-Property Temporary Difference	1,537,456	2,091,918	1,223,366		254	957	254	19,962		2,425,013
17	TOTAL Gas (Total of lines 11 thru 16)	1,537,456	2,091,918	1,223,366			957		19,962		2,425,013
18	TOTAL Other	573,721 ^(c)			25,148	409,522					189,347 ^(d)
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	160,133,126	66,752,643	79,835,793	25,148	409,522	148,766		3,380,868		149,897,704
20	Classification of TOTAL										
21	Federal Income Tax	137,533,881	54,283,287	66,173,950	11,622	344,354	101,273		3,268,996		128,478,209
22	State Income Tax	22,599,245	12,469,356	13,661,843	13,526	65,168	47,493		111,872		21,419,499
23	Local Income Tax										

NOTES

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

	Beginning of Year
Electric Account 283	\$ 158,021,949
Tax Rate Changes	13,812,304
Subtotal	\$ 171,834,253
Temporary differences excluded from State jurisdictional rates	(35,904,403)
	\$ 135,929,850

Functionalization of Account 283 excluding temporary differences excluded from rates, beginning of year

Production	36.57 %
Transmission	8.24 %
Distribution	49.04 %
General	6.15 %

(b) Concept: AccumulatedDeferredIncomeTaxesOther

	End of Year
Electric Account 283	\$ 147,283,344
Tax Rate Changes	10,599,206
Subtotal	\$ 157,882,550
Temporary differences excluded from State jurisdictional rates	(8,255,746)
	\$ 149,626,804

Functionalization of Account 283 excluding temporary differences excluded from rates, End of year

Production	33.28 %
Transmission	14.24 %
Distribution	40.93 %
General	11.55 %

(c) Concept: AccumulatedDeferredIncomeTaxesOther

	Beginning of Year
Other Non-Utility Property 283	\$ 573,721
Temporary differences excluded from State jurisdictional rates	573,721
	\$ —

(d) Concept: AccumulatedDeferredIncomeTaxesOther

	End of Year
Other Non-Utility Property 283	\$ 189,347
Temporary differences excluded from State jurisdictional rates	189,347
	\$ —

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	^(g) Unamortized Investment Tax Credits	7,937,263	190	15,916,069	64,582,929	56,604,123
2	^(h) OPEB Regulatory Tracker	25,000,545	926	8,268,604	1,871,047	18,602,988
3	Pension Regulatory Tracker	86,098,011	926	45,352,735	11,095,269	51,840,545
4	Derivative Mark-to-Market	18,787,351	175	18,787,352	9,863,531	9,863,530
5	Deferred Income Taxes - Pension and OPEB	47	190			47
6	Asset Retirement Obligation	524,408,349	182.3	524,408,349	691,064,141	691,064,141
7	⁽ⁱ⁾ Missouri Energy Efficiency Investment Act (MEEIA)	5,209,126	182.3, 254, 407, 419, 431, 440, 442	43,789,790	41,300,606	2,719,942
8	^(j) Proposition C Renewable Energy Costs - Other	424,215	509	363,624	3,634,488	3,695,079
9	^(k) Over Collection of Previously Authorized Regulatory Amortization	1,054,309	182.3, 407	1,214,152	774,447	614,604
10	^(l) FERC ROE Case	1,413,473				1,413,473
11	^(m) Taxes - Temporary Differences	990,734,108	182.3, 190, 282, 283	165,876,919	53,362,200	878,219,389
12	⁽ⁿ⁾ Excess Deferred Tax Tracker	6,010,371	407	15,863,503	312,135	(9,540,997)
13	^(o) Other Post Employment Benefits	148,167,178	128, 146, 228, 254	25,311,057	53,520,650	176,376,771
14	Pension Benefits	54,568,541	128, 146, 228, 254	60,439,116	31,637,273	25,766,698
15	^(p) PAYS Program Spend Deferral and Tracker-Gas	563,361	488	25,613	302,555	840,303
16	^(q) Renewable Energy Standard Rate Adjustment Mechanism (RESRAM) - Contra Account	(452,557)	182.3, 254, 407, 419, 431	259,558	712,115	
17	^(r) Nuclear Production Tax Credits				89,939,208	89,939,208
18	^(s) Securitization Rush Island Safe Closure and Decommissioning				46,907,500	46,907,500

19	(a) Securitization Rush Island Materials and Supplies Inventory		182.3	382,980	18,259,889	17,876,909
20	(a) Inflation Reduction Act Tracker				14,731,647	14,731,647
21	(a) Rush Island - Accounting Authority Order		182.3, 431	4,299,654	17,174,434	12,874,780
22	(a) Securitization Rush Island Coal Inventory Costs				1,486,650	1,486,650
23	(a) Securitized Utility Tariff Rider (SUR)				134,284	134,284
24	(a) Securitization Rush Island Plant Retirement				117,013	117,013
41	TOTAL	1,869,923,691		930,559,075	1,152,784,011	2,092,148,627

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities			
Applies to Page 278: For balances with amortization amounts determined in a regulatory rate review, the monthly amortization amounts, calculated based on a specified amortization period, will continue to be recorded at the end of the specified amortization period until completion of the next regulatory rate review in accordance with Missouri Public Service Commission Cases ER-2022-0337 and GR-2021-0241. The net under or over recovery associated with continuing amortizations will be considered during a future regulatory rate review.			
Applies to line 1, column (a): Amortized over the expected life of the underlying assets.			
(b) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities			
The following footnote applies to the OPEB Regulatory Tracker and Pension Tracker.			
Established per Missouri Public Service Commission Cases ER-2007-0002 and GR-2007-0003.			
By order of the Missouri Public Service Commission in Case ER-2022-0337, the remaining balance of the first through eighth electric accumulation periods is being amortized over 2 years starting July 2023. The ninth accumulation period is being amortized over 5 years starting July 2023 per MoPSC Case ER-2022-0337. The amortization period for the next accumulation period will be determined in a future regulatory rate review.			
The first gas accumulation period is fully amortized. The second gas accumulation period was amortized over 5 years starting September 2019, per MoPSC Case GR2019-0077. The third gas accumulation period is being amortized over 5 years starting March 2022 per MoPSC Case GR-2021-0241. The amortization period for the next accumulation period will be determined in a future regulatory rate review.			
(c) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities			
Established per Missouri Public Service Commission Case EO-2012-0142.			
MEEIA plan year runs February through January. Amounts will be accumulated during that period and amortized starting in February of the following year. The MEEIA regulatory balances are comprised of:			
	Beginning Balance 12/31/2023	Ending Balance 12/31/2024	
MEEIA-Program Costs	\$ 1,825,780	\$ (488,327)	
MEEIA-Throughput Disincentive	3,417,956	3,228,450	
MEEIA-Ordered Adjustments	(34,610)	(20,181)	
Total	\$ 5,209,126	\$ 2,719,942	
(d) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities			
Established per Missouri Public Service Commission Case ER-2011-0029.			
The fifth accumulation period is being amortized over 3 years beginning March 2022, per MoPSC Case ER-2021-0240. The sixth accumulation period is being amortized over 3 years beginning July 2023, per MoPSC Case ER-2022-0337.			
(e) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities			
Amortization period will be established in a future regulatory rate review.			
(f) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities			
Established per Missouri Public Service Commission Case ER-2016-0179.			
Amortization period will be established in a future regulatory rate review.			
(g) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities			
Represents deferred income taxes that will be refunded to customers related to other tax liabilities and depreciation differences recorded at rates in excess of current statutory rates. Amortization began in August 2018 for federal electric balances and January 2019 for gas balances associated with the effects of the Tax Cuts and Jobs Act in accordance with Missouri Public Service Commission Case ER-2018-0362 and GR-2019-0077, respectively. Depreciation differences are amortized over the expected life of the related assets.			
The amortization periods for federal electric and gas balances are 10 years for certain balances and the expected life of the related assets for certain plant-related balances. The amortization period for state electric balances is 5 years. Amortization began in April 2020 for state electric balances in accordance with MoPSC Case ER-2019-0335.			
(h) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities			
Established per Missouri Public Service Commission Case ER-2018-0362.			
The second electric accumulation period is being amortized over 3 years beginning March 2022, per MoPSC Case ER-2021-0240. The third electric accumulation period is being amortized over 3 years beginning July 2023, per MoPSC Case ER-2022-0337. The amortization for the current electric accumulation period will be determined in a future rate review.			
The first gas accumulation period is being amortized over 3 years starting March 2022 per MoPSC Case GR-2021-0241. The amortization for the current gas accumulation period will be determined in a future rate review.			
(i) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities			
The following footnote applies to Other Post Employment Benefits and Pension Benefits.			
Amortization period of 10 years with an annual update of the regulatory liability balance based on changes in actuarial assumptions, capital market conditions and actual demographic experience.			
(j) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities			

Established per Missouri Public Service Commission Case GR-2021-0241.
The costs associated with energy efficiency projects under the Pay As You Save (PAYS) program are deferred and earn a return. Participating customers begin receiving charges for a portion of project costs 45 days after project completion, and related deferred costs begin amortizing over the payment term of the agreement. An amortization period for remaining costs, not recovered from program participants, will be determined in a future regulatory rate review.
(k) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities
The following footnote applies to RESRAM-Contra Account.
Established per Missouri Public Service Commission Case EA-2018-0202.
The RESRAM-Contra Account was in an asset position as of December 31, 2024. See page 232.
(l) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities
The following footnote relates to Nuclear Production Tax Credits (PTCs) generated by the Company's Callaway Nuclear Energy Center, and tracked in the Inflation Reduction Act tracker as established per MoPSC Case ER-2022-0337. An amortization period will be established in a future rate review.
(m) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities
Established per MoPSC Case EF-2024-0021. Represents bond proceeds related to the securitization order applicable to safe closure and decommissioning costs to be incurred in the closure of the Rush Island Energy Center. An amortization period will be established in a future rate review.
(n) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities
Established per MoPSC Case EF-2024-0021. Represents bond proceeds related to the securitization order applicable to material and supplies inventory costs to be incurred in the closure of the Rush Island Energy Center. An amortization period will be established in a future rate review.
(o) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities
The following footnote relates to certain Production Tax Credits (PTCs) and Investment Tax Credits (ITCs) being tracked in the Inflation Reduction Act Tracker as established per MoPSC Case ER-2022-0337. An amortization period will be established in a future rate review.
(p) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities
Established per MoPSC Case EF-2024-0021. Represents base rate revenues related to the Rush Island Energy Center collected after the energy center was retired, which will be refunded to customers in the future. An amortization period will be established in a future rate review.
(q) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities
Established per MoPSC Case EF-2024-0021. Represents bond proceeds related to the securitization order applicable to coal inventory costs to be incurred in the closure of the Rush Island Energy Center. An amortization period will be established in a future rate review.
(r) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities
Established per MoPSC Case EF-2024-0021. The accumulation periods are generally 6 months followed by an amortization period of 6 months.
(s) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities
Established per MoPSC Case EF-2024-0021. Represents the difference between bond proceeds related to the securitization order applicable to plant retirement costs compared to actual costs incurred in the closure of the Rush Island Energy Center. An amortization period will be established in a future rate review.

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Electric Operating Revenues

- The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
- Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
- Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
- If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
- Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2.
- Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
- See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
- For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
- Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	1,633,293,927	1,572,882,223	13,001,145	12,803,699	1,095,619	1,087,971
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	1,311,074,433	1,278,549,355	13,604,181	13,451,192	163,544	160,866
5	Large (or Ind.) (See Instr. 4)	311,205,819	305,402,853	4,094,258	3,975,939	3,554	3,576
6	(444) Public Street and Highway Lighting	18,415,673	18,613,347	64,364	71,150	1,751	1,748
7	(445) Other Sales to Public Authorities	95,547	92,571	300	156	1	1
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	3,274,085,399	3,175,540,349	30,764,248	30,302,136	1,264,469	1,254,162
11	(447) Sales for Resale	461,102,497	371,186,455	4,011,469	4,145,158	3	7
12	TOTAL Sales of Electricity	3,735,187,896	3,546,726,804	34,775,717	34,447,294	1,264,472	1,254,169
13	(Less) (449.1) Provision for Rate Refunds	1,520,381	(10,184,704)				
14	TOTAL Revenues Before Prov. for Refunds	3,733,667,515	3,556,911,508	34,775,717	34,447,294	1,264,472	1,254,169
15	Other Operating Revenues						

16	(450) Forfeited Discounts	5,280,359	5,249,918				
17	(451) Miscellaneous Service Revenues	(a)5,654,207	3,496,529				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	39,805,983	37,506,164				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	(b)11,742,343	9,070,051				
22	(456.1) Revenues from Transmission of Electricity of Others	32,858,626	31,317,847				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	95,341,518	86,640,509				
27	TOTAL Electric Operating Revenues	3,829,009,033	3,643,552,017				

Line 12, column (b) includes \$ (a)4,532,000 of unbilled revenues.

Line 12, column (d) includes 37,118 MWH relating to unbilled revenues

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: MiscellaneousServiceRevenues

Miscellaneous Service Revenues (451) consist of the following:

	<u>Current Year</u>	<u>Prior Year</u>
Connection, Re-Connection, and Change Fee	\$ 544,427	\$ 626,966
Customer Installations (Adjustments)	2,425,354	1,180,786
Pole Attachment Related Fees	2,532,125	1,577,200
Program Service Charges	152,301	111,577
	<u>\$ 5,654,207</u>	<u>\$ 3,496,529</u>

(b) Concept: OtherElectricRevenue

Other Electric Revenues (456) consist of the following:

	<u>Current Year</u>	<u>Prior Year</u>
Miscellaneous Customer Credits (Debits)	\$ 745,439	\$ 663,920
Customer Line Relocation Requests	151,838	—
Sale of Salvage Surplus Materials	80,244	58,378
Timely Payment Allowance on Sales Tax	1,794,574	1,744,171
Affiliate Billing Revenue	2,727,872	523,971
Dock Fees	1,956,226	1,734,397
Distribution Facility Rentals	4,286,150	4,345,214
	<u>\$ 11,742,343</u>	<u>\$ 9,070,051</u>

(c) Concept: RevenueFromSalesOfElectricityUnbilled

	<u>MWH</u>	<u>Revenue</u>
Unbilled amounts included in Total Sales to Ultimate Consumers - Line 10	37,027	4,528,000
Unbilled amounts included in (447) Sales for Resale - Line 11	91	4,000
Total Unbilled Revenue	<u>37,118</u>	<u>\$ 4,532,000</u>

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Not applicable				
46	TOTAL				

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential No. 1	3,612,147	430,320,694	285,918	12,634	0.1191
2	Residential T-O-U No. 1	9,337,938	1,188,199,524	809,701	11,533	0.1272
3	Residential Private Area Lighting No. 5/6	19,714	11,435,709			0.5801
4	Variation in Unbilled	31,346	3,338,000			0.1065
41	TOTAL Billed Residential Sales	12,969,799	1,629,955,927	1,095,619	11,838	0.1257
42	TOTAL Unbilled Rev. (See Instr. 6)	31,346	3,338,000			0.1065
43	TOTAL	13,001,145	1,633,293,927	1,095,619	11,866	0.1256

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	General Service No. 2	3,012,729	358,048,862	145,560	20,698	0.1188
2	General Service T-O-U No. 2	129,919	14,277,056	7,311	17,770	0.1099
3	Large General Service No. 3	6,456,955	614,052,750	9,741	662,864	0.0951
4	Large General Service T-O-U No. 3	62,960	5,610,983	61	1,032,131	0.0891
5	Primary Service No. 4/11	3,706,224	290,297,892	493	7,517,696	0.0783
6	Primary Service T-O-U No. 4/11	210,321	14,940,278	18	11,684,500	0.0710
7	Street & Outdoor Lighting No. 5/6	36,230	13,931,612	360	100,639	0.3845
8	Variation in Unbilled	(11,157)	(85,000)			0.0076
41	TOTAL Billed Small or Commercial	13,615,338	1,311,159,433	163,544	83,252	0.0963
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(11,157)	(85,000)			0.0076
43	TOTAL Small or Commercial	13,604,181	1,311,074,433	163,544	83,184	0.0964

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	General Service No. 2	82,585	9,275,822	2,415	34,197	0.1123
2	General Service T-O-U No. 2	504	54,861	9	56,000	0.1089
3	Large General Service No. 3	687,135	67,622,907	907	757,591	0.0984
4	Primary Service No. 4/11	3,036,231	215,157,165	209	14,527,421	0.0709
5	Primary Service T-O-U No. 4/11	269,734	17,613,801	8	33,716,750	0.0653
6	Street & Outdoor Lighting No. 5/6	638	198,263	6	106,333	0.3108
7	Variation in Unbilled	17,431	1,283,000			0.0736
41	TOTAL Billed Large (or Ind.) Sales	4,076,827	309,922,819	3,554	1,147,109	0.0760
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	17,431	1,283,000			0.0736
43	TOTAL Large (or Ind.)	4,094,258	311,205,819	3,554	1,152,014	0.0760

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

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4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Street Lighting - No. 5	28,656	15,086,064	426	67,268	0.5265
2	Street Lighting - No. 5/6	1,449	638,256	9	161,000	0.4405
3	Street Lighting - No. 6	34,852	2,699,353	1,316	26,483	0.0775
4	Variation in Unbilled	(593)	(8,000)			0.0135
41	TOTAL Billed Public Street and Highway Lighting	64,957	18,423,673	1,751	37,097	0.2836
42	TOTAL Unbilled Rev. (See Instr. 6)	(593)	(8,000)			0.0135
43	TOTAL	64,364	18,415,673	1,751	36,758	0.2861

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3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Contract Rate - Unmetered Sales	300	95,547	1	300,000	0.3185
2	Variation in Unbilled					
41	TOTAL Billed Other Sales to Public Authorities	300	95,547	1	300,000	0.3185
42	TOTAL Unbilled Rev. (See Instr. 6)					0.0000
43	TOTAL	300	95,547	1	300,000	0.3185

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SALES OF ELECTRICITY BY RATE SCHEDULES

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3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
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22						
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24						
25						

26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL			1,520,381		

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

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2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	30,727,221	3,269,557,399	1,264,469	24,300	0.1064
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	37,027	4,528,000			0.1223
43	TOTAL - All Accounts	30,764,248	3,274,085,399	1,264,469	24,330	0.1064

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

[\(a\)](#) Concept: RevenueFromSalesOfElectricityByRateSchedules

Listed below are the amounts recovered from customers in 2024 by rate schedule related to the fuel adjustment clause.

Number and Title of Rate Schedule	FAC Recovered
Account 440 – Residential Sales	
Residential No. 1	\$ 11,223,070
Residential T-O-U No. 1	29,546,852
Private Area Lighting No. 5/6	59,029
Total Residential Sales	\$ 40,828,951
Account 442 – Commercial Sales	
General Service No. 2	\$ 9,400,472
General Service T-O-U No. 2	399,480
Large General Service No. 3	20,065,224
Large General Service T-O-U No. 3	195,653
Primary Service No. 4/11	11,168,359
Primary Service T-O-U No. 4/11	638,113
Private Area Lighting No. 5/6	108,766
Total Commercial Sales	\$ 41,976,067
Account 442 – Industrial Sales	
General Service No. 2	\$ 253,053
General Service T-O-U No. 2	1,537
Large General Service No. 3	2,124,032
Primary Service No. 4/11	9,058,198
Primary Service T-O-U No. 4/11	815,868
Customer Owned Lighting No. 5/6	1,932
Total Industrial Sales	\$ 12,254,620
Account 444 – Public	
Street & Highway Lighting	
Street Lighting – No. 5	\$ 86,592
Street Lighting – No. 5/6	4,348
Street Lighting – No. 6	107,629
Total Public Street/Mun. Lighting	\$ 198,569
Total Amount Recovered	\$ 95,258,207

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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SALES FOR RESALE (Account 447)

- Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settler for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
- Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest affiliation the respondent has with the purchaser.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to the supplier's service to its own ultimate consumers.

LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

- Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (g) through (k).
- In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
- For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its maximum peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
- Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
- Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
- The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last-line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.
- Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		Megawatt Hours Sold (g)	REVENUE			Total (h) (i)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)	
1	Requirements Service										
2	Perry, MO	RQ	1				8,925		392,122		392,122
3	Linneus, MO	RQ	1				1,765		78,924		78,924

4	VARIATION IN UNBILLED	RQ					91		4,000		
5	Non-Requirements Service										
6	Associated Electric Coop	SF	1				109		2,691		
7	Kansas City Power and Light	SF	1	16				176,000			17
8	Midcontinent Independent System Operator, Inc. (MISO)	SF	1	224,096			2,900,025	375,346,783	59,897,653	11,921,725 ^(a)	447,16
9	Southwest Power Pool (SPP)	SF	1				1,100,554		13,436,426	21,953 ^(b)	13,43
10	Realized Gain/Loss on Derivative Transactions									(175,780) ^(c)	(17
15	Subtotal - RQ						10,781		475,046		47
16	Subtotal-Non-RQ						4,000,688	375,522,783	73,336,770	11,767,898	460,68
17	Total						4,011,469	375,522,783	73,811,816	11,767,898	461,10

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: OtherChargesRevenueSalesForResale

Detail of the Other Charges resulting from sales to the MISO are as follows:

Ancillary Revenue Adjustments	\$	(1,777)
Ancillary Ramp Capability		74,672
Day-Ahead RSG Make Whole Payment		784,877
Net Regulation Adjustment Amount		194,118
Real-Time Excessive/Deficient Energy Deployment Charge		(906,211)
Regulation & Frequency Reserve Service		2,609,698
Spinning Reserve Service		2,930,115
Supplemental Reserve Service		1,124,064
Real-Time RSG Make Whole Payment		860,333
Price Volatility Make Whole Payment		1,782,228
Short-Term Reserve		1,344,736
System Support Resource		1,124,872
Total	\$	11,921,725

(b) Concept: OtherChargesRevenueSalesForResale

Detail of the Other Charges resulting from sales to the SPP are as follows:

Ancillary Ramp Capability	\$	21,406
Ancillary Uncertainty Reserve		(1)
Net Regulation Adjustment Amount		652
Regulation & Frequency Reserve Service		(56)
Spinning Reserve Service		(38)
Supplemental Reserve Service		(10)
Total	\$	21,953

(c) Concept: OtherChargesRevenueSalesForResale

Represents gains and losses on derivative instruments lacking a physical delivery of power and broker fees.

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	4,839,864	4,613,717
5	(501) Fuel	336,855,459	355,552,304
6	(502) Steam Expenses	15,054,110	14,330,975
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	14,092,734	14,706,749
10	(506) Miscellaneous Steam Power Expenses	13,002,546	13,454,603
11	(507) Rents	17,940	18,940
12	(509) Allowances	8,641,893	7,192,430
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	392,504,546	409,869,718
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	8,700,553	8,923,943
16	(511) Maintenance of Structures	8,116,169	10,120,691
17	(512) Maintenance of Boiler Plant	39,013,374	39,426,959
18	(513) Maintenance of Electric Plant	6,814,690	5,980,549
19	(514) Maintenance of Miscellaneous Steam Plant	6,026,992	11,115,296
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	68,671,778	75,567,438
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	461,176,324	485,437,156
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	28,057,895	27,106,952
25	(518) Fuel	80,366,750	67,501,388
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		

30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses	48,784,174	49,741,419
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	157,208,819	144,349,759
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	10,967,499	10,485,077
36	(529) Maintenance of Structures	11,766,463	13,132,738
37	(530) Maintenance of Reactor Plant Equipment	34,684,128	43,340,758
38	(531) Maintenance of Electric Plant	5,756,017	5,060,741
39	(532) Maintenance of Miscellaneous Nuclear Plant	5,380,066	6,122,520
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	68,554,173	78,141,834
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	225,762,992	222,491,593
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	1,153,029	1,110,230
45	(536) Water for Power	422,010	417,656
46	(537) Hydraulic Expenses	542,316	457,555
47	(538) Electric Expenses	1,624,521	1,895,361
48	(539) Miscellaneous Hydraulic Power Generation Expenses	4,863,653	4,926,005
49	(540) Rents	370	
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	8,605,899	8,806,807
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	991,292	1,017,138
54	(542) Maintenance of Structures	2,805,584	1,524,381
55	(543) Maintenance of Reservoirs, Dams, and Waterways	115,318	145,519
56	(544) Maintenance of Electric Plant	1,217,802	1,510,529
57	(545) Maintenance of Miscellaneous Hydraulic Plant	546,941	706,062
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	5,676,937	4,903,629
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	14,282,836	13,710,436
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,139,149	425,748
63	(547) Fuel	26,047,888	24,570,637
64	(548) Generation Expenses	1,273,340	2,594,807

64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	6,031,418	4,810,812
66	(550) Rents	6,302,483	5,301,869
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	40,794,278	37,703,873
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	1,048,601	3,866,753
71	(553) Maintenance of Generating and Electric Plant	12,458,697	11,510,382
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,012,826	866,770
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	14,520,124	16,243,905
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	55,314,402	53,947,778
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	485,038,736	380,574,902
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	3,299,986	2,752,678
78	(557) Other Expenses	61,124,197	100,762,392
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	549,462,919	484,089,972
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	1,305,999,473	1,259,676,935
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	524,054	441,286
85	(561.1) Load Dispatch-Reliability	62,125	53,265
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	422,881	602,104
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	6,988,949	5,544,454
89	(561.5) Reliability, Planning and Standards Development	57,077	53,447
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	502,524	398,661
93	(562) Station Expenses	387,045	350,114
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	2,846	6,150
95	(564) Underground Lines Expenses		

96	(565) Transmission of Electricity by Others	92,980,965	80,438,249
97	(566) Miscellaneous Transmission Expenses	5,579,691	5,402,313
98	(567) Rents	8,664,727	3,277,463
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	116,172,884	96,567,506
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	149,567	122,419
102	(569) Maintenance of Structures	18,526	28,318
103	(569.1) Maintenance of Computer Hardware	13,653	16,177
104	(569.2) Maintenance of Computer Software	426,584	578,749
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,185,835	1,275,067
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	6,080,163	7,311,147
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	578,010	405,313
111	TOTAL Maintenance (Total of Lines 101 thru 110)	8,452,338	9,737,190
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	124,625,222	106,304,696
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	6,530,748	6,321,007
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	6,530,748	6,321,007
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		

130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	6,530,748	6,321,007
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	8,087,284	9,052,373
135	(581) Load Dispatching	1,464,570	1,376,351
136	(582) Station Expenses	2,657,030	2,161,419
137	(583) Overhead Line Expenses	12,962,341	13,427,611
138	(584) Underground Line Expenses	5,325,173	5,280,494
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	2,578,353	2,658,597
140	(586) Meter Expenses	3,606,292	4,218,783
141	(587) Customer Installations Expenses	808,014	672,313
142	(588) Miscellaneous Expenses	29,345,177	30,878,335
143	(589) Rents	379,293	327,912
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	67,213,527	70,054,188
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,326,807	1,324,637
147	(591) Maintenance of Structures	341,627	733,337
148	(592) Maintenance of Station Equipment	12,332,660	12,529,290
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	54,587,631	63,366,694
150	(594) Maintenance of Underground Lines	4,318,472	5,652,582
151	(595) Maintenance of Line Transformers	1,240,023	1,463,140
152	(596) Maintenance of Street Lighting and Signal Systems	880,643	982,258
153	(597) Maintenance of Meters	710,622	759,657
154	(598) Maintenance of Miscellaneous Distribution Plant	2,485,390	2,087,113
155	TOTAL Maintenance (Total of Lines 146 thru 154)	78,223,875	88,898,708
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	145,437,402	158,952,896
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,616,151	771,666
160	(902) Meter Reading Expenses	5,892,439	8,129,863
161	(903) Customer Records and Collection Expenses	35,153,496	36,297,175
162	(904) Uncollectible Accounts	9,826,787	9,751,787
163	(905) Miscellaneous Customer Accounts Expenses	123,074	117,336

164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	52,611,947	55,067,827
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	85,152,202	89,034,290
169	(909) Informational and Instructional Expenses	2,395,071	3,480,340
170	(910) Miscellaneous Customer Service and Informational Expenses	554,784	765,079
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	88,102,057	93,279,709
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	913,889	161,447
176	(913) Advertising Expenses	1,394	209,438
177	(916) Miscellaneous Sales Expenses	1,957	2,541
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	917,240	373,426
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	70,267,290	61,834,799
182	(921) Office Supplies and Expenses	36,744,071	35,548,605
183	(Less) (922) Administrative Expenses Transferred-Credit	15,953,884	13,216,417
184	(923) Outside Services Employed	41,754,850	35,096,643
185	(924) Property Insurance	9,296,250	8,021,815
186	(925) Injuries and Damages	79,106,886	16,497,340
187	(926) Employee Pensions and Benefits	(72,105,018)	(7,254,320)
188	(927) Franchise Requirements	1,363	1,363
189	(928) Regulatory Commission Expenses	24,533,821	22,551,378
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	44,275	73,754
192	(930.2) Miscellaneous General Expenses	10,997,703	13,202,746
193	(931) Rents	13,668,192	12,741,087
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	198,355,799	185,098,793
195	Maintenance		
196	(935) Maintenance of General Plant	3,748,695	3,448,305
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	202,104,494	188,547,098

198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	1,926,328,583	1,868,523,594
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Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: LoadDispatchReliability					
Account 561.1 includes 561.BA balancing authority costs recovered through Midcontinent Independent System Operator, Inc. Schedule 24 of:					
<table style="width: 100%; border-collapse: collapse;"> <thead> <tr> <th style="text-align: center; border-bottom: 1px solid black;">2024</th> <th style="text-align: center; border-bottom: 1px solid black;">2023</th> </tr> </thead> <tbody> <tr> <td style="text-align: center;">\$62,125</td> <td style="text-align: center;">\$53,265</td> </tr> </tbody> </table>	2024	2023	\$62,125	\$53,265	
2024	2023				
\$62,125	\$53,265				

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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PURCHASED POWER (Account 555)

- Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for imbalanced exchanges).
- Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain the respondent has with the seller.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes prc planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consume

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not l meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside fi availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlk

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an

- In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the co schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
- For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly avera monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types c Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand durin supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a me
- Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the l
- Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchar the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charge (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
- The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Pur column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on
- Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		Den Char (i)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
1	Requirements Service		^(b) See Note								
2	Associated Electric Cooperative	RQ					4,284				
3	Consolidated Electric Cooperative	RQ					101				

4	City of Perry, MO	RQ									
5	Tri-County Electric Cooperative	RQ					53				
6	Other Service										
7	^(a) Cogeneration	OS					13,175				
8	Direct Energy Business Marketing	OS									2
9	Kansas City Power and Light	OS									
10	Karbone	OS									5
11	Midcontinent Independent System Operator, Inc. (MISO)	OS					3,712,003				356,7
12	Occidental Power Service	OS									
13	Pioneer Prairie Wind Farm	OS					155,373				
14	PJM Interconnection	OS									
15	Southwest Power Pool (SPP)	OS					170,143				
16	The Energy Authority	OS									
15	TOTAL						4,055,132	0	0	0	357,6

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

This line aggregates all purchases made under net metering and qualified facilities.

(b) Concept: RateScheduleTariffNumber

This footnote applies to all lines on page 326, column (c):

Midcontinent Independent System Operator, Inc. (MISO) FERC Electric Tariff Vol. No. 1.

(c) Concept: OtherChargesOfPurchasedPower

Financial Transmission Rights	\$	9,862
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(d) Concept: OtherChargesOfPurchasedPower

Detail of the Other Charges resulting from purchases from the MISO are as follows:

MISO Activities	\$	946,200
Auction Revenue Rights		(17,611,302)
Inadvertent Energy		(187,615)
Energy Losses		18,186,038
Revenue Neutrality Uplift		11,969,777
Revenue Sufficiency Guarantees		1,078,569
Financial Transmission Rights		(3,142,119)
Ancillary Regulation		1,654,759
Ancillary Spinning		1,232,915
Ancillary Supplemental		227,285
Demand Response Allocation Uplift		(2,554,492)
Short-Term Reserve		1,703,418
Total	\$	13,503,433

(e) Concept: OtherChargesOfPurchasedPower

Detail of the Other Charges resulting from purchases from PJM are as follows:

Ancillary Regulation	\$	(1,293)
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(f) Concept: OtherChargesOfPurchasedPower

Detail of the Other Charges resulting from purchases from SPP are as follows:

Energy Losses	\$	(189)
Revenue Neutrality Uplift		269,287
Revenue Sufficiency Guarantees		4,837
Ancillary Supplemental		(1)
Demand Response Allocation Uplift		4
Schedule 1A Administrative		119,192
Total	\$	393,130

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "w

- Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-tr for the quarter.
- Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
- Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
- In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any account provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
- In column (e), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or contract designations under which
- Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the sub where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for v contract.
- Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column demand not stated on a megawatts basis and explain.
- Report in column (i) and (j) the total megawatthours received and delivered.
- In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge st column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement service rendered.
- The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on 1
- Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY	
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)
1	^{(a),(b),(c)} Midcontinent Independent System Operator, Inc. (MISO)	Union Electric Company (UEC)	MISO		MISO FERC Electric Tariff Vol. No. 1	VARIOUS	VARIOUS			
2	Southwest Power Pool (SPP)	UEC	SPP		SPP FERC Electric Tariff Vol. No. 1	VARIOUS	VARIOUS			
35	TOTAL							0	0	0

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: PaymentByCompanyOrPublicAuthority

UEC is a transmission owning member of the MISO Regional Transmission Organization (RTO). UEC is not a transmission provider. UEC does not sell transmission services. Instead, UEC receives revenue from the MISO for the sale of transmission services to third party customers. MISO distributes the revenue that it receives to the transmission owners.

Because UEC, Ameren Transmission Company of Illinois (ATXI), and Wabash Valley Power Association (Wabash) and Missouri Joint Municipal Electric Utility Commission (MEC) are Transmission Owners within the AMMO pricing zone of the MISO RTO, each is allocated a portion of the revenue collected for the AMMO pricing zone based on its respective revenue requirement. The Wabash and MEC loads located in the AMMO pricing zone are included in UEC's reported peaks. ATXI serves no load. Therefore, the AMMO pricing zone load is equal to UEC reported load, which includes all retail and wholesale load in the pricing zone.

(b) Concept: PaymentByCompanyOrPublicAuthority

This footnote applies to line 1, column (d):

Includes all revenue collected by the MISO and distributed to UEC under the MISO Transmission Owner's Agreement. This includes all types of transmission service classifications.

(c) Concept: PaymentByCompanyOrPublicAuthority

This footnote applies to line 1, columns (h), (i), and (j):

As all revenue is collected by the MISO and distributed to UEC under the MISO Transmission Owner's Agreement, billing demand and energy transfer information is unavailable.

(d) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers

The demand charges listed in this column include:

\$	8,018,126	Schedule 7 (Firm PTP Transmission)
	1,239,028	Schedule 8 (Non-Firm PTP Transmission)
	12,557,330	Schedule 9 (Network Transmission)
	10,578,959	Schedule 26, 37, and 38 (Network Upgrade Transmission Expansion)
	32,393,443	
\$		

(e) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

The other charges listed in this column include:

\$	376,956	Schedule 1 (Scheduling, System Control & Dispatch Service)
	55,599	Schedule 24 (Control Area Operator Cost Recovery)
	24,137	Pass Through of MISO Transmission Costs to Wholesale Customers
	456,692	
\$		

(f) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

The other charges listed in this column include:

\$	8,491	Schedule 2 (Reactive Supply & Voltage Control)
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Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1	Not applicable				
40	TOTAL				

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to-Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	^(a) Midcontinent Independent System Operator, Inc. (MISO)	^(d) FNS	32,934,650	^(e) 32,934,650	88,626,427		^(g) 68,492	88,694,919
2	Associated Electric Cooperative	FNS	340	340	155,994			155,994
3	^(b) Ameren Illinois Company (AIC)	OS					^(g) 513,864	513,864
4	^(c) Ameren Transmission Company of Illinois (ATXI)	OS					^(g) 967,582	967,582
5	Huck Finn	OS					^(g) 48,807	48,807
6	Kansas City Power and Light	FNS			1,775,965			1,775,965
7	PJM Interconnection LLC	OS					^(g) (2)	(2)
8	MidAmerican Energy	OS					^(g) 817,634	817,634
9	Otter Tail Power Company	OS					^(g) 6,202	6,202
	TOTAL		32,934,990	32,934,990	90,558,386	0	2,422,579	92,980,965

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Union Electric Company (UEC) is a transmission owning member of the MISO Regional Transmission Organization (RTO). UEC is not a transmission provider. UEC has a transmission reservation to serve its bundled native load customers. It also has transmission reservations to sell power outside of MISO. Under these reservations, UEC incurs charges from MISO.

(b) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Affiliate

(c) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Affiliate

(d) Concept: StatisticalClassificationCode

This includes charges for all types of MISO transmission service reservations made by UEC.

(e) Concept: TransmissionOfElectricityByOthersEnergyDelivered

Reflects updated settlement data. These MISO megawatts reflect amounts on MISO Schedule 10 invoices. The megawatts are related to:

311,897	Point to Point
245,141	Network Integrated Transmission Service
32,377,612	Native Load
32,934,650	

(f) Concept: OtherChargesTransmissionOfElectricityByOthers

These charges are related to:

\$ 66,687	Schedule 1 (Scheduling, System Control & Dispatch Service)
1,805	Schedule 33 (Black Start Service)
\$ 68,492	

(g) Concept: OtherChargesTransmissionOfElectricityByOthers

These charges are related to Interconnection Facility Service Agreement.

(h) Concept: OtherChargesTransmissionOfElectricityByOthers

These charges are related to Interconnection Facility Service Agreement.

(i) Concept: OtherChargesTransmissionOfElectricityByOthers

These charges are related to Interconnection Facility Service Agreement.

(j) Concept: OtherChargesTransmissionOfElectricityByOthers

These charges are related to:

\$ (2)	Schedule 2 (Reactive Supply & Voltage Control)
--------	--

(k) Concept: OtherChargesTransmissionOfElectricityByOthers

These charges are related to Interconnection Facility Service Agreement.

(l) Concept: OtherChargesTransmissionOfElectricityByOthers

These charges are related to Interconnection Facility Service Agreement.

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,233,402
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	1,381,906
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	2,622,338
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than \$5,000	
6	Public Relations Expenses:	
7	Cision US Inc	21,368
8	Contract Services	
9	Items less than \$5,000 each - Public Relations Expenses	
10	Other Miscellaneous General Expenses:	
11	Moody's Investors Service	244,177
12	Association of Edison Illuminating Companies	13,025
13	City of St. Louis Missouri Business License Tax	16,617
14	S & P Global	322,081
15	Public Company Accounting Oversight Board	42,174
16	Financial Accounting Standards Board	5,461
17	Items less than \$5,000 each - Other Miscellaneous General Expenses	(678)
18	Apportioned to Gas Department	(533,174)
19	Labor allocations from Ameren Services Company	4,629,006
46	<u>TOTAL</u>	10,997,703

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

- Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
- Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
- Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
- If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			97,140,679		97,140,679
2	Steam Production Plant	198,078,482				198,078,482
3	Nuclear Production Plant	88,789,515				88,789,515
4	Hydraulic Production Plant- Conventional	12,759,163		755,715		13,514,878
5	Hydraulic Production Plant- Pumped Storage	3,299,262				3,299,262
6	Other Production Plant	63,600,031				63,600,031
7	Transmission Plant	50,658,688		444,625		51,103,313
8	Distribution Plant	227,201,412				227,201,412
9	Regional Transmission and Market Operation					
10	General Plant	52,057,983				52,057,983
11	Common Plant-Electric					
12	TOTAL	696,444,536		98,341,019		794,785,555

B. Basis for Amortization Charges

This footnote applies to Part B. Basis for Amortization Charges. Amortization Charges - Missouri, Illinois and Iowa Properties Provision for amortization was made in the amount of \$622,397 at the rate of 1% per annum on portions of Accounts 330 and 350 representing all expenditures recorded in such accounts except expenditures for land held under unrestricted fee title. Provision for amortization was made in the amount of \$577,943 for Intangible Plant - Franchises and Consents (Account 302) related to hydraulic production plant. Asset amortization occurs over a 25-year or 40-year life. Amortization for Intangible Plant - Miscellaneous Intangible Plant (Account 303) occurs over a 2 and 15-year life.

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
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12	N/A - No new Depr Rates						
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Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) related cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than \$25,000) may be grouped.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	EXPENSES INCURRED DURING YEAR			AMORTIZED		
						CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Am (k)
						Department (f)	Account No. (g)	Amount (h)			
1	Payments to cover assessment of Respondent's portion of estimated expenses of the Missouri Public Service Commission incurred during the year: (Electric)										
2	Electric Case No. AO-2023-0417	3,498,198		3,498,198		Electric	928	3,498,198			
3	Electric Case No. OO-2024-0364	3,704,375		3,704,375		Electric	928	3,704,375			
4	FEDERAL ENERGY REGULATORY COMMISSION										
5	Payment under License for Project 259-Missouri to cover costs of administration of Federal Power Act, F.E.R.C.	1,828,774		1,828,774		Electric	928	1,828,774			

6	Payment under License for Project 2277-MO to cover costs of administration of Federal Power Act, F.E.R.C.					Electric	928			
7	Midcontinent Independent System Operator (MISO)	4,030,904		4,030,904		Electric	928	4,030,904		
8	NUCLEAR REGULATORY COMMISSION:									
9	Fees	7,496,788		7,496,788		Electric	928	7,496,788		
10	Professional services in connection with regulatory matters. (Electric)		970,236	970,236		Electric	928	970,236		
11	MINOR ITEMS:									
12	Miscellaneous (Electric)		3,004,546	3,004,546		Electric	928	3,004,546		
13	Payments to cover assessment of Respondent's portion of estimated expenses of the MoPSC incurred during the year: (Gas)									
14	Gas Case No. AO-2023-0417	267,788		267,788		Gas	928	267,788		
15	Gas Case No. OO-2024-0364	196,281		196,281		Gas	928	196,281		
16	Professional services in connection with regulatory matters. (Gas)		131,583	131,583		Gas	928	131,583		
17	Miscellaneous (Gas)		214,080	214,080		Gas	928	214,080		
46	TOTAL	21,023,108	4,320,445	25,343,553				25,343,553		

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).

2. Indicate in column (a) the applicable classification, as shown below:
Classifications:

- | | |
|---|--|
| Electric R, D and D Performed Internally: | Overhead
Underground |
| Generation | Distribution |
| hydroelectric | Regional Transmission and Market Operation |
| Recreation fish and wildlife | Environment (other than equipment) |
| Other hydroelectric | Other (Classify and include items in excess of \$50,000.) |
| Fossil-fuel steam | Total Cost Incurred |
| Internal combustion or gas turbine | |
| Nuclear | Electric, R, D and D Performed Externally: |
| Unconventional generation | Research Support to the electrical Research Council or the |
| Siting and heat rejection | Electric Power Research Institute |
| Transmission | Research Support to Edison Electric Institute |
| | Research Support to Nuclear Power Groups |
| | Research Support to Others (Classify) |
| | Total Cost Incurred |

3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing \$50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under \$50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	B(1)	Electric Power Research Institute		3,313,992	524, 549, 557, 930	3,313,992	
2	B(4)	Lawrence Berkeley		133,331	930	133,331	
3	B(4)	Evergy Metro		(199,999)	588, 930	(199,999)	
4	B(4)	Western Ecosytems		63,437	549	63,437	
5	B(4)	General RD&D Expenses		1,874	549	1,874	
6	A(6)	General RD&D Expenses	219,575		524, 549, 557, 930	219,575	
7	Totals		219,575	3,312,635		3,532,210	

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	118,023,081		
4	Transmission	4,709,957		
5	Regional Market			
6	Distribution	32,957,214		
7	Customer Accounts	18,663,366		
8	Customer Service and Informational	8,608,982		
9	Sales	497,269		
10	Administrative and General	72,255,880		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	255,715,749		
12	Maintenance			
13	Production	70,483,406		
14	Transmission	2,036,448		
15	Regional Market			
16	Distribution	31,044,784		
17	Administrative and General	1,048,847		
18	TOTAL Maintenance (Total of lines 13 thru 17)	104,613,485		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	188,506,487		
21	Transmission (Enter Total of lines 4 and 14)	6,746,405		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	64,001,998		
24	Customer Accounts (Transcribe from line 7)	18,663,366		
25	Customer Service and Informational (Transcribe from line 8)	8,608,982		
26	Sales (Transcribe from line 9)	497,269		
27	Administrative and General (Enter Total of lines 10 and 17)	73,304,727		

28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	360,329,234	9,229,681	369,558,915
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply	771,107		
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution	8,468,031		
37	Customer Accounts	2,935,114		
38	Customer Service and Informational	67,337		
39	Sales	56,137		
40	Administrative and General	7,865,688		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	20,163,414		
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			
48	Distribution	2,353,933		
49	Administrative and General	51,490		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	2,405,423		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	771,107		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)	10,821,964		
58	Customer Accounts (Line 37)	2,935,114		
59	Customer Service and Informational (Line 38)	67,337		
60	Sales (Line 39)	56,137		
61	Administrative and General (Lines 40 and 49)	7,917,178		

62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	22,568,837	528,559	23,097,396
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	382,898,071	9,758,240	392,656,311
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	259,859,345	17,685,495	277,544,840
69	Gas Plant	13,368,037	909,989	14,278,026
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	273,227,382	18,595,484	291,822,866
72	Plant Removal (By Utility Departments)			
73	Electric Plant	16,602,597	162,667	16,765,264
74	Gas Plant	1,140,497	11,333	1,151,830
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	17,743,094	174,000	17,917,094
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Other Work in Progress	843,576	19,483	863,059
80	Other Income & Deductions	1,871,737	43,480	1,915,217
81	Preliminary Surveys & Investigations	3,064,108	71,712	3,135,820
82	Unamortized Debt Expense	(13,189)	(180)	(13,369)
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	5,766,232	134,495	5,900,727
96	TOTAL SALARIES AND WAGES	679,634,779	28,662,219	708,296,998

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	28,746,719	48,131,223	71,795,297	(a)101,484,691
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(17,960,042)	(38,975,095)	(51,500,193)	(59,897,653)
4	Transmission Rights	(938,929)	(9,907,289)	(15,269,806)	(20,753,421)
5	Ancillary Services	(377,006)	(554,013)	(1,957,906)	(2,551,037)
6	Other Items (list separately)				
7	Net Capacity	(218,452)	(1,302,992)	(8,301,146)	(18,579,287)
8	Other MISO	4,511,402	10,184,835	18,197,007	24,886,167
9	PJM Interconnection:				
10	Energy				
11	Net Purchases (Account 555)				
12	Net Purchases (Account 555.1)				
13	Net Sales (Account 447)				
14	Transmission Rights - PJM				
15	Net Ancillary Services - PJM				
16	Other PJM	(1,226)	(1,226)	(1,226)	(1,293)
17	Southwest Power Pool (SPP):				
18	Energy				
19	Net Purchases (Account 555)	(938,027)	140,518	875,990	1,761,416
20	Net Purchases (Account 555.1)				
21	Net Sales (Account 447)	(2,011,633)	(6,244,585)	(9,920,141)	(13,436,426)
22	Transmission Rights - SPP				
23	Net Ancillary Services - SPP	(20,707)	(20,709)	(20,670)	(21,953)
24	Other SPP	135,534	211,998	266,547	393,130
46	TOTAL	10,927,633	1,662,665	4,163,753	13,284,334

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower

Midcontinent Independent System Operator (MISO) settlement statement information is furnished in rows 1-8. PJM Interconnection (PJM) settlement statement information is furnished in rows 9-16. Southwest Power Pool (SPP) settlement statement information is furnished in rows 17-24.

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch			66,687			376,956
2	Reactive Supply and Voltage			(2)			8,491
3	Regulation and Frequency Response			1,654,759			1,898,201
4	Energy Imbalance						
5	Operating Reserve - Spinning			1,232,915			2,930,077
6	Operating Reserve - Supplement			227,285			1,124,054
7	Other			1,703,418			1,439,037
8	Total (Lines 1 thru 7)			4,885,062			7,776,816

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedAmount

Union Electric Company (UEC) is a transmission owning member of the Midcontinent Independent System Operator, Inc. (MISO) Regional Transmission Organization (RTO). UEC is not a transmission provider. UEC does not sell transmission services or ancillary services directly. Instead, UEC receives revenues from transmission services and ancillaries sold by MISO. MISO distributes the revenue that it receives to the transmission owners.

(b) Concept: AncillaryServicesPurchasedAmount

Other amount consists of Short-Term Reserve.

(c) Concept: AncillaryServicesSoldAmount

Other amount includes:

\$	(1,777) Combined Adjustments to Revenue Related to Regulation, Spinning, and Supplemental Ancillary Services.
	96,078 Ancillary Ramp Capability
	1,344,736 Short-Term Reserve
\$	1,439,037

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: AMMO PRICING ZONE									
1	January	7,232	14	19	6,680	552				
2	February	5,219	17	9	4,775	444				
3	March	4,905	19	8	4,540	365				
4	Total for Quarter 1				15,995	1,361	0	0	0	0
5	April	5,110	15	18	4,679	431				
6	May	6,110	21	17	5,634	476				
7	June	7,586	25	16	7,004	582				
8	Total for Quarter 2				17,317	1,489	0	0	0	0
9	July	7,484	15	17	6,899	585				
10	August	7,722	27	17	7,149	573				
11	September	6,688	20	17	6,153	535				
12	Total for Quarter 3				20,201	1,693	0	0	0	0
13	October	5,073	5	17	4,630	443				
14	November	4,818	30	19	4,417	401				
15	December	5,873	6	9	5,366	507				
16	Total for Quarter 4				14,413	1,351	0	0	0	0
17	Total				67,926	5,894	0	0	0	0

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

[\(a\)](#) Concept: MonthlyPeakLoadExcludingIsoAndRto

This page includes data for the AMMO Pricing Zone.

Because Union Electric Company (UEC), Ameren Transmission Company of Illinois (ATXI), Wabash Valley Power Association (Wabash) and Missouri Joint Municipal Electric Utility Commission (MEC) are Transmission Owners within the AMMO pricing zone of the Midcontinent Independent System Operator, Inc. (MISO) Regional Transmission Organization (RTO), each is allocated a portion of the revenue collected for the AMMO pricing zone based on its respective revenue requirement. The Wabash and MEC loads located in the AMMO pricing zone are included in UEC's reported peaks. ATXI serves no load. Therefore, the AMMO pricing zone load is equal to UEC reported load, which includes all retail and wholesale load in the pricing zone. The AMMO pricing zone within the MISO transmission system includes the load served by UEC.

[\(b\)](#) Concept: DayOfMonthlyPeakExcludingIsoAndRto

This footnote applies to lines 1-17, all columns:
These amounts are subject to change over time as meter settlement data is available.

[\(c\)](#) Concept: FirmNetworkServiceForSelf

Excludes UEC retail load in Southeast Missouri located in the Entergy Arkansas, Inc. (EAI) pricing zone.

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: 0									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2025-04-08	Year/Period of Report End of: 2024/ Q4
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ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	30,764,248
3	Steam	18,243,158	23	Requirements Sales for Resale (See instruction 4, page 311.)	10,781
4	Nuclear	10,525,784	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	4,000,688
5	Hydro-Conventional	1,385,386	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage	340,475	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other	2,037,177	27	Total Energy Losses	1,337,940
8	Less Energy for Pumping	473,455	27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	32,058,525	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	36,113,657
10	Purchases (other than for Energy Storage)	4,055,132			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)	0			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	36,113,657			

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: 0					
29	January	3,685,393	358,173	6,726	14	19
30	February	2,807,414	406,745	4,805	17	9
31	March	2,705,153	363,450	4,571	19	8
32	April	2,658,314	481,860	4,706	15	18
33	May	3,224,120	702,557	5,674	21	17
34	June	3,410,549	296,830	7,053	25	16
35	July	3,427,569	327,967	6,949	15	17
36	August	3,373,037	226,520	7,199	27	17
37	September	2,737,467	190,522	6,197	20	17
38	October	2,505,466	288,665	4,669	5	17
39	November	2,541,515	171,741	4,446	30	19
40	December	3,037,660	185,658	5,405	6	9
41	Total	36,113,657	4,000,688			

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

[\(a\)](#) Concept: EnergyActivity

This page includes data for Union Electric Company.
This footnote applies to column (b) for lines 29-40:
Disclosed megawatt-hours are net energy for load served by Union Electric Company generating units.

[\(b\)](#) Concept: MonthlyPeakLoad

This footnote applies to columns (d), (e), and (f) for lines 29-40:
These amounts are subject to change over time as meter settlement data updates.

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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Steam Electric Generating Plant Statistics

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a term basis report the Btu content or the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: Audrain CTG	Plant Name: Callaway	Plant Name: Fairgrounds CT	Plant Name: Goose Creek CT	Plant Name: Kinmundy	Plant Name: Labadie	Plant Name: Maryland Heights LF	Plant Name: Mexico CT
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Gas Turbine	Nuclear	Gas Turbine	Gas Turbine	Gas Turbine	Steam	Gas Turbine	Combustion Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Const.	Conventional	Peaking - Automatic	Outdoor Const.	Outdoor Const.	Conventional	Conventional	Outdoor Const.
3	Year Originally Constructed	2001	1984	1974	2003	2001	1970	2012	1978
4	Year Last Unit was Installed	2001	1984	1974	2003	2001	1973	2012	1978
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	692	1,236	68	581	250	2,428	15	54
6	Net Peak Demand on Plant - MW (60 minutes)	609	1,254	49	268	120	2,479	11	71
7	Plant Hours Connected to Load	535	8,634	20	75	32	8,761	7,282	22
8	Net Continuous Plant Capability (Megawatts)	661	1,217	61	485	226	2,427	10	60

9	When Not Limited by Condenser Water	720	1,237	67	540	244	2,460		67
10	When Limited by Condenser Water	608	1,194	55	438	210	2,372		54
11	Average Number of Employees		793				266	4	
12	Net Generation, Exclusive of Plant Use - kWh	146,382,307	10,525,784,000	136,008	762,695	(6,225)	14,401,705,570	55,818,876	766,871
13	Cost of Plant: Land and Land Rights	1,673,155	9,793,885	781	510,869	294,483	13,364,165	17,669	20,537
14	Structures and Improvements	3,872,842	1,010,001,591	446,940	3,689,540	2,968,962	158,400,335	7,577,290	272,385
15	Equipment Costs	165,309,990	2,546,579,792	5,714,995	199,686,707	104,285,047	1,729,974,483	49,668,865	8,541,838
16	Asset Retirement Costs		92,749,580				8,707,875		
17	Total cost (total 13 thru 20)	170,855,987	3,659,124,848	6,162,716	203,887,116	107,548,492	1,910,446,858	57,263,824	8,834,760
18	Cost per KW of Installed Capacity (line 17/5) Including	246.9017	2,960.4570	90.6282	350.9245	430.1940	786.8397	3,817.5883	163.6067
19	Production Expenses: Oper, Supv, & Engr	25,473	28,057,895	35,058	16,982	16,982	1,509,948	48,116	35,058
20	Fuel	7,014,210	80,366,750	116,160	1,053,302	444,533	235,765,807	2,001,846	177,999
21	Coolants and Water (Nuclear Plants Only)								
22	Steam Expenses						4,927,512		
23	Steam From Other Sources								
24	Steam Transferred (Cr)								
25	Electric Expenses	134,166			72,058	74,142	6,765,437	337,977	
26	Misc Steam (or Nuclear) Power Expenses	59,852	48,782,905	138	10,734	111,184	7,023,719	40,128	647
27	Rents		370						

28	Allowances											
29	Maintenance Supervision and Engineering		10,967,499					4,147,481				
30	Maintenance of Structures	25,393	11,766,463	25,033	36,033	270,244	3,422,524	370,708	4,110			
31	Maintenance of Boiler (or reactor) Plant		34,684,128				22,498,358					
32	Maintenance of Electric Plant	501,582	5,756,017	177,680	516,971	1,157,905	2,689,669	852,782	55,654			
33	Maintenance of Misc Steam (or Nuclear) Plant	35,962	5,380,066		874	10,345	3,620,281	221,141				
34	Total Production Expenses	7,796,638	225,762,093	354,069	1,706,954	2,085,335	292,370,736	3,872,698	273,468			
35	Expenses per Net kWh	0.0533	0.0214	2.6033	2.2381		0.0203	0.0694	0.3566			
35	Plant Name	Audrain CTG	Callaway	Fairgrounds CT	Goose Creek CT	Kinmundy	Kinmundy	Labadie	Labadie	Maryland Heights LF	Mexico CT	Mot CT
36	Fuel Kind	Gas	Nuclear	Oil	Gas	Gas	Oil	Coal	Oil	Gas	Oil	Oil
37	Fuel Unit	Mcf	MMBTU	bbl	Mcf	Mcf	bbl	T	bbl	Mcf	bbl	bbl
38	Quantity (Units) of Fuel Burned	1,757,195	104,929,521	858	81,029	11,714	868	8,178,357	14,754	763,461	1,457	
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,039		134,022	1,054	1,050	260,582	8,922	135,954	1,000	136,936	138
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.971		118.027	12.930	26.630	120.358	28.524	108.864	2.608	100.241	99
41	Average Cost of Fuel per Unit Burned	3.971	0.766	134.638	12.930	26.630	150.070	28.630	112.827	2.608	121.563	94
42	Average Cost of Fuel Burned per Million BTU	3.820	0.766	23.919	12.273	25.363	13.712	1.605	19.759	2.608	21.137	16
43	Average Cost of Fuel Burned per kWh Net Gen	0.048	0.008	0.854	1.381	(71.411)		0.016		0.036	0.232	1
44	Average BTU per kWh Net Generation	12,477	9,969	35,518	111,933	(3,501,558)		10,139		13,677	10,923	88

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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Hydroelectric Generating Plant Statistics

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Keokuk	FERC Licensed Project No. 459 Plant Name: Osage
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1913	1931
4	Year Last Unit was Installed	1913	1953
5	Total installed cap (Gen name plate Rating in MW)	130	266
6	Net Peak Demand on Plant-Megawatts (60 minutes)	155	250
7	Plant Hours Connect to Load	8,783	7,830
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	150	240
10	(b) Under the Most Adverse Oper Conditions	149	235
11	Average Number of Employees	29	27
12	Net Generation, Exclusive of Plant Use - kWh	888,278,869	497,107,422
13	Cost of Plant		
14	Land and Land Rights	7,233,798	10,543,391
15	Structures and Improvements	24,466,128	14,847,068
16	Reservoirs, Dams, and Waterways	38,460,840	86,567,521
17	Equipment Costs	193,935,814	101,841,903
18	Roads, Railroads, and Bridges	114,926	77,445
19	Asset Retirement Costs		
20	Total cost (total 13 thru 20)	264,211,506	213,877,328
21	Cost per KW of Installed Capacity (line 20 / 5)	2,032.396	804.050
22	Production Expenses		
23	Operation Supervision and Engineering	302,290	522,944
24	Water for Power		422,010
25	Hydraulic Expenses	289,708	240,533

26	Electric Expenses	458,566	1,165,955
27	Misc Hydraulic Power Generation Expenses	1,821,340	1,073,745
28	Rents		
29	Maintenance Supervision and Engineering	517,485	261,892
30	Maintenance of Structures	627,277	1,438,950
31	Maintenance of Reservoirs, Dams, and Waterways	24,512	4,649
32	Maintenance of Electric Plant	187,459	444,363
33	Maintenance of Misc Hydraulic Plant	91,515	146,962
34	Total Production Expenses (total 23 thru 33)	4,320,152	5,722,003
35	Expenses per net kWh	0.0049	0.0115

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Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 2277 Plant Name: Taub Sauk
1	Type of Plant Construction (Conventional or Outdoor)	Conventional
2	Year Originally Constructed	1963
3	Year Last Unit was Installed	1963
4	Total installed cap (Gen name plate Rating in MW)	450
5	Net Peak Demand on Plant-Megawatts (60 minutes)	443
6	Plant Hours Connect to Load While Generating	1,424
7	Net Plant Capability (in megawatts)	440
8	Average Number of Employees	19
9	Generation, Exclusive of Plant Use - kWh	340,474,930
10	Energy Used for Pumping	473,455,000
11	Net Output for Load (line 9 - line 10) - Kwh	(132,980,070)
12	Cost of Plant	
13	Land and Land Rights	327,672
14	Structures and Improvements	25,838,981
15	Reservoirs, Dams, and Waterways	12,350,735
16	Water Wheels, Turbines, and Generators	113,632,726
17	Accessory Electric Equipment	14,371,985
18	Miscellaneous Powerplant Equipment	6,713,401
19	Roads, Railroads, and Bridges	383,064
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	173,618,564
22	Cost per KW of installed cap (line 21 / 4)	385.819

23	Production Expenses	
24	Operation Supervision and Engineering	327,795
25	Water for Power	
26	Pumped Storage Expenses	54,298
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	1,968,568
29	Rents	
30	Maintenance Supervision and Engineering	211,915
31	Maintenance of Structures	739,357
32	Maintenance of Reservoirs, Dams, and Waterways	86,157
33	Maintenance of Electric Plant	585,980
34	Maintenance of Misc Pumped Storage Plant	308,464
35	Production Exp Before Pumping Exp (24 thru 34)	4,282,534
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	4,282,534
38	Expenses per kWh (line 37 / 9)	0.0126
39	Expenses per kWh of Generation and Pumping (line 37/(line 9 + line 10))	0.0053

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GENERATING PLANT STATISTICS (Small Plants)

- Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped than 10,000 Kw installed capacity (name plate rating).
- Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and of the facts in a footnote. If licensed project, give project number in footnote.
- List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Part 1.
- If net peak demand for 60 minutes is not available, give the which is available, specifying period.
- If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kilowatt Hours (k)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)	
1	Other:										
2	SOLAR PHOTOVOLTAIC										
3	O'Fallon Renewable Energy Center	2015	4.5	4.0	2,283,922	16,031,065	3,562,459	11,235		7,731	—
4	Barnes Jewish Solar	2019	1.6	0.7	845,647	4,404,754	2,805,576				—
5	Lambert Community Solar	2019	0.9	0.8	1,380,583	2,082,130	2,210,329			8,860	—
6	South St. Louis Renewable Energy Center	2021	0.2	0.2	249,275	1,291,744	6,727,833				—
7	Cape Girardeau Renewable Energy Center Solar	2022	1.2	1.0	1,671,694	5,013,754	4,178,128				—
8	Montgomery Community Solar Center	2022	5.7	5.8	8,830,791	12,940,522	2,270,267			17,887	—
9	Fee Fee Renewable Energy Center	2023	0.5	0.5	719,189	3,768,075	7,536,150			3,190	—
10	North Metro Renewable Energy Center	2023	0.2	0.2	304,302	1,698,401	8,492,005				—
11	Delmar Renewable Energy Center	2023	0.3	0.3	459,692	2,559,972	8,533,240				—
12	House Springs Renewable Energy Center	2023	0.2	0.2	359,169	1,778,269	8,891,345				—
13	Huck Finn Solar Energy Center	2024	200.0	173.0	6,822,000	351,722,987	1,758,615	212,023		9,855	—

14	Boomtown Solar Energy Center	2024	150.0	127.0	4,429,000	317,360,500	2,115,737	108,803		220	—
15	Cass County Solar Energy Center	2024	149.9	141.0	331,000	313,361,691	2,089,914	489,641		18,997	—
16	WIND										
17	High Prairie (163 units @ 2.2 MW each & 12 units at 3.45 MW each)(Amounts are for total of all 175 units)	2020	400.0	388.6	648,681,371	684,058,012	1,710,145	6,731,573		3,095,628	—
18	Atchison Wind (51 units @ 4.2 MW each, 18 units at 2.0 MW each & 22 units at 2.2 MW each) (Amounts are for total of all 91 units)	2021	298.6	289.7	930,777,000	535,276,079	1,792,619	4,596,293		3,271,946	—

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FOOTNOTE DATA

(a) Concept: NetGenerationExcludingPlantUse

The following footnote applies to lines 3-18, column (e):
Measured in kilowatt-hours.

22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32										
33										
34										
35	TOTAL			0	0	0	0	0	0	0

24									
25									
26									
27									
28									
29									
30									
31									
32									
33									
34									
35									
36	TOTAL			0	0	0	0	0	0

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TRANSMISSION LINE STATISTICS

- Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolt by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
- Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report :
- Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
- Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; c the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction
- Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such for the line designated.
- Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if y support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
- Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, gi a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furni ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are ac company.
- Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determ
- Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conduct and Mate
	From (a)	To (b)	Operating (c)	Designated (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)		
1	MASON	OSAGE_1&2	138		Lattice Tower	0.93		1	^(b) 336.4 KCM ACSR
2	MASON	OSAGE_1&2	138		Lattice Tower	20.91	20.91	2	954 KCM ACSR
3	MASON	OSAGE_1&2	138		Steel Pole	0.03	0.05	2	2156 KCM ACSR
4	MASON	OSAGE_1&2	138		Steel Pole	1.02		1	336.4 KCM ACSR
5	MASON	OSAGE_1&2	138		Steel Pole	0.01		2	556.5 KCM AAC
6	MASON	OSAGE_1&2	138		Steel Pole	0.21	0.20	1	954 KCM ACSR
7	MASON	OSAGE_1&2	138		Wood Pole	0.07		1	
8	MASON	OSAGE_1&2	138		Wood Pole	0.04		1	250 KCM CU
9	MASON	OSAGE_1&2	138		Wood Pole	149.99		1	336.4 KCM ACSR
10	MASON	OSAGE_1&2	138		Wood Pole	0.10		1	795 KCM ACSS
11	MASON	OSAGE_1&2	138		Wood Pole	23.36		1	954 KCM ACSR
12	RIVERMINES	OSAGE_1&2	138		Lattice Tower	0.02		2	300 KCM CU

13	RIVERMINES	OSAGE_1&2	138		Lattice Tower	0.24	0.25	2	336.4 KCM ACSR
14	RIVERMINES	OSAGE_1&2	138		Lattice Tower	0.01		2	556.5 KCM ACSS
15	RIVERMINES	OSAGE_1&2	138		Lattice Tower	91.67	91.72	2	556.5 KCM ACSS/HS
16	RIVERMINES	OSAGE_1&2	138		Lattice Tower	23.93		2	954 KCM ACSR
17	RIVERMINES	OSAGE_1&2	138		Lattice Tower		0.11	2	954 KCM ACSS
18	RIVERMINES	OSAGE_1&2	138		Lattice Tower		23.61	2	954 KCM ACSS/HS
19	RIVERMINES	OSAGE_1&2	138		Steel Pole	3.62	3.77	2	556.5 KCM ACSS/HS
20	RIVERMINES	OSAGE_1&2	138		Wood Pole	1.16		1	954 KCM ACSR
21	RIVERMINES	OSAGE_1&2	138		Wood Pole	1.17		1	954 KCM ACSS
22	RIVERMINES	OSAGE_1&2	138		Wood Pole	0.21		1	954 KCM ACSS/HS
23	CAHOKIA	RIVERMINES_1&2	138		Lattice Tower	0.72		1	300 KCM ACSR
24	CAHOKIA	RIVERMINES_1&2	138		Lattice Tower	23.93		1	556.5 KCM ACSS
25	CAHOKIA	RIVERMINES_1&2	138		Lattice Tower	3.34		1	556.5 KCM ACSS/HS
26	CAHOKIA	RIVERMINES_1&2	138		Lattice Tower	0.05		1	954 KCM ACSR
27	CAHOKIA	RIVERMINES_1&2	138		Steel Pole	0.05		1	336.4 KCM ACSR
28	CAHOKIA	RIVERMINES_1&2	138		Steel Pole	0.07		1	4/0 AWG (
29	CAHOKIA	RIVERMINES_1&2	138		Steel Pole	0.07		1	556.5 KCM ACSS
30	CAHOKIA	RIVERMINES_1&2	138		Steel Pole	0.27		1	556.5 KCM ACSS/HS
31	CAHOKIA	RIVERMINES_1&2	138		Wood Pole	1.12		1	1590 KCM ACSR
32	CAHOKIA	RIVERMINES_1&2	138		Wood Pole	8.95		1	336.4 KCM ACSR
33	MERAMEC	WATSON_1&2	138		Lattice Tower		3.41	2	795 KCM AAC
34	MERAMEC	WATSON_1&2	138		Lattice Tower	0.64		1	954 KCM ACSR
35	MERAMEC	WATSON_1&2	138		Steel Pole	2.38	2.40	2	350 KCM CU
36	MERAMEC	WATSON_1&2	138		Steel Pole	3.69	0.24	2	795 KCM AAC
37	MERAMEC	WATSON_1&2	138		Steel Pole	0.83		2	795 KCM ACSR
38	MERAMEC	WATSON_1&2	138		Wood Pole	0.09		1	2156 KCM ACSR

39	MERAMEC	WATSON_1&2	138		Wood Pole	20.33		1	795 KCM ACSR
40	MERAMEC	WATSON_1&2	138		Wood Pole	0.10		1	954 KCM ACSR
41	VENICE	CAMPBELL_MALINE_PAGE	138		Lattice Tower		1.09	2	2156 KCM ACSR/HS
42	VENICE	CAMPBELL_MALINE_PAGE	138		Lattice Tower		0.04	2	350 KCM CU
43	VENICE	CAMPBELL_MALINE_PAGE	138		Lattice Tower	3.29	4.02	1	350 KCM CU-HD
44	VENICE	CAMPBELL_MALINE_PAGE	138		Lattice Tower	3.10	3.11	2	954 KCM ACSS
45	VENICE	CAMPBELL_MALINE_PAGE	138		Steel Pole	0.04	0.04	2	
46	VENICE	CAMPBELL_MALINE_PAGE	138		Steel Pole	3.05	3.05	2	ACSS
47	VENICE	CAMPBELL_MALINE_PAGE	138		Steel Pole	2.05	0.94	1	2156 KCM ACSR
48	VENICE	CAMPBELL_MALINE_PAGE	138		Steel Pole		0.09	2	350 KCM CU-HD
49	VENICE	CAMPBELL_MALINE_PAGE	138		Steel Pole	0.44	0.37	2	954 KCM ACSS
50	SIOUX	SEDALIA	161		Lattice Tower	1.22		1	795 KCM ACSR
51	SIOUX	SEDALIA	138		Lattice Tower		9.16	2	795 KCM ACSS
52	SIOUX	SEDALIA	161		Lattice Tower		64.05	2	954 KCM ACSR
53	SIOUX	SEDALIA	138		Steel Pole		0.92	2	336.4 KCM ACSR
54	SIOUX	SEDALIA	161		Steel Pole		1.74	2	954 KCM ACSR
55	SIOUX	SEDALIA	161		Wood Pole	68.06		1	795 KCM ACSR
56	SIOUX	SEDALIA	138		Wood Pole	9.39		1	1192.5 KCMIL AC
57	RIVERMINES	JOPPA_1	161		Lattice Tower	2.27		1	795 KCM ACSR
58	RIVERMINES	JOPPA_1	161		Steel Pole	0.24		1	795 KCM ACSR
59	RIVERMINES	JOPPA_1	161		Steel Pole	0.25		1	954 KCM ACAR
60	RIVERMINES	JOPPA_1	161		Wood Pole	75.13		1	795 KCM ACSR
61	RIVERMINES	JOPPA_1	161		Wood Pole	4.14		1	954 KCM ACAR
62	RIVERMINES	JOPPA_1	161		Wood Pole	0.24		1	954 KCM ACSR
63	PAGE	KEOKUK	161		Lattice Tower	0.54		1	207.6 KCM CCSR
64	PAGE	KEOKUK	161		Lattice Tower	0.14		1	477 KCM ACSR

65	PAGE	KEOKUK	138		Lattice Tower	8.26		1	556.5 KCM ACSS
66	PAGE	KEOKUK	138		Lattice Tower	11.56		1	556.5 KCM ACSS/HS
67	PAGE	KEOKUK	138		Lattice Tower	0.48		1	795 KCM ACSS
68	PAGE	KEOKUK	138		Lattice Tower		12.71	2	954 KCM ACSR
69	PAGE	KEOKUK	138		Steel Pole	0.68		1	556.5 KCM ACSS/HS
70	PAGE	KEOKUK	138		Steel Pole		6.50	2	954 KCM ACSR
71	PAGE	KEOKUK	161		Wood Pole	0.04		1	477 KCM ACSR
72	PAGE	KEOKUK	138		Wood Pole	4.87		1	556.5 KCM ACSS
73	PAGE	KEOKUK	138		Wood Pole	0.16		1	556.5 KCM ACSS/HS
74	PAGE	KEOKUK	138		Wood Pole	0.37		1	954 KCM ACSR
75	OSAGE	MOBERLY	161		Lattice Tower	0.77		1	556.5 KCM ACSR
76	OSAGE	MOBERLY	161		Steel Pole	0.01		1	795 KCM ACSR
77	OSAGE	MOBERLY	161		Wood Pole	77.46		1	556.5 KCM ACSR
78	OSAGE	MOBERLY	161		Wood Pole	20.42		1	556.5 KCM ACSS
79	OSAGE	MOBERLY	161		Wood Pole	15.11		1	795 KCM ACSR
80	OSAGE	MOBERLY	161		Wood Pole	0.03		1	954 KCM ACSR
81	ROXFORD	SIOUX_BERKELEY	138		Lattice Tower	0.76	0.76	2	2156 KCM ACSR
82	ROXFORD	SIOUX_BERKELEY	138		Lattice Tower	16.96	16.97	2	954 KCM ACSR
83	ROXFORD	SIOUX_BERKELEY	138		Lattice Tower	2.02	2.82	2	954 KCM ACSS
84	ROXFORD	SIOUX_BERKELEY	138		Steel Pole		0.01	2	556.5 KCM AAC
85	ROXFORD	SIOUX_BERKELEY	138		Steel Pole	9.85	3.76	2	954 KCM ACSR
86	ROXFORD	SIOUX_BERKELEY	138		Wood Pole	0.85	0.87	2	2156 KCM ACSR
87	ROXFORD	SIOUX_BERKELEY	138		Wood Pole	0.10	0.11	2	954 KCM ACSR
88	ST FRANCOIS	NEW BOURBON	138		Wood Pole	24.67		1	795 KCM ACSR
89	OSAGE PLANT	OSAGE SUB	138		Lattice Tower	0.81		1	336.4 KCM ACSR

90	MASON	MERAMEC_1&2	138		Lattice Tower		0.01	2	556.5 KCM ACSR
91	MASON	MERAMEC_1&2	138		Lattice Tower	23.16	22.94	2	954 KCM ACSR
92	MASON	MERAMEC_1&2	138		Steel Pole	0.02	0.03	2	556.5 KCM ACSR
93	MASON	MERAMEC_1&2	138		Steel Pole	0.33	0.11	2	954 KCM ACSR
94	MASON	MERAMEC_1&2	138		Wood Pole	0.03		1	954 KCM ACSR
95	SIOUX	HILLS_6	345	345	Lattice Tower	0.02		2	2156 KCM ACSR
96	SIOUX	HILLS_6	345		Lattice Tower	0.95		1	795 KCM ACSR
97	SIOUX	HILLS_6	345		Lattice Tower	22.65		2	795 KCM ACSS
98	SIOUX	HILLS_6	345		Lattice Tower	0.09		2	954 KCM ACSR
99	SIOUX	HILLS_6	345		Lattice Tower	42.72		2	954 KCM ACSS
100	SIOUX	HILLS_6	345		Steel Pole	0.69		2	795 KCM ACSS
101	SIOUX	HILLS_6	345		Steel Pole	0.29		2	954 KCM ACSS
102	SIOUX	HILLS_6	345		Steel Pole		2.24	2	954 KCM ACSS/HS
103	SIOUX	HILLS_6	345		Wood Pole	186.80		1	795 KCM ACSR
104	SIOUX	HILLS_6	345		Wood Pole	0.23		1	954 KCM ACSR
105	SIOUX	HILLS_6	345		Wood Pole	0.38		1	954 KCM ACSS/HS
106	PAGE	BERKELEY_1&2	138		Lattice Tower	6.12	6.12	2	954 KCM ACSR
107	PAGE	BERKELEY_1&2	138		Steel Pole	0.14	0.12	2	954 KCM ACSR
108	RUSH ISLAND	SHAWNEE	345		Lattice Tower	1.66		1	795 KCM ACSR
109	RUSH ISLAND	SHAWNEE	345		Steel Pole	15.07		1	795 KCM ACSR
110	RUSH ISLAND	SHAWNEE	345		Wood Pole	70.00		1	795 KCM ACSR
111	RUSH ISLAND	SHAWNEE	345		Wood Pole	44.81		1	954 KCM ACSR
112	CLARK	PEA RIDGE_3	138		Wood Pole	18.08		1	336.4 KCM ACSR
113	CAHOKIA	ASHLEY_VENICE_1&2	138		Lattice Tower	0.52	0.52	2	2156 KCM ACSR
114	CAHOKIA	ASHLEY_VENICE_1&2	138		Steel Pole	0.13	0.13	2	2156 KCM ACSR

115	SIoux	VIELE	161		Lattice Tower	16.12		1	477 KCM ACSR
116	SIoux	VIELE	138		Lattice Tower	9.30		1	795 KCM ACSS
117	SIoux	VIELE	161		Lattice Tower	1.26		1	954 KCM ACSR
118	SIoux	VIELE	161		Steel Pole	0.16		1	
119	SIoux	VIELE	161		Steel Pole		3.92	2	1192.5 KCMIL ACSS/HS
120	SIoux	VIELE	138		Steel Pole	0.92		1	336.4 KCM ACSR
121	SIoux	VIELE	161		Steel Pole	0.10		1	477 KCM ACSR
122	SIoux	VIELE	138		Steel Pole	1.11		1	795 KCM ACSR
123	SIoux	VIELE	138		Steel Pole	5.31	5.31	2	954 KCM ACSR
124	SIoux	VIELE	161		Wood Pole	1.88		1	1192.5 KCMIL AC
125	SIoux	VIELE	161		Wood Pole	1.00		1	477 KCM ACSR
126	SIoux	VIELE	138		Wood Pole	0.91		1	636 KCM ACSR
127	SIoux	VIELE	161		Wood Pole	139.78		1	795 KCM ACSR
128	SIoux	VIELE	138		Wood Pole	4.40		1	795 KCM ACSS
129	SIoux	VIELE	138		Wood Pole	5.71		1	954 KCM ACSR
130	CAHOKIA	MERAMEC_1&2	138		Lattice Tower	0.15	0.15	2	954 KCM AAC
131	CAHOKIA	MERAMEC_1&2	138		Lattice Tower	1.30	1.30	2	954 KCM ACSR
132	CAHOKIA	MERAMEC_1&2	138		Steel Pole		0.03	2	795 KCM AAC
133	CAHOKIA	MERAMEC_1&2	138		Steel Pole	2.56	2.64	2	954 KCM ACSR
134	CONWAY	MERAMEC_3&4	138		Lattice Tower	33.50	33.52	2	954 KCM ACSR
135	CONWAY	MERAMEC_3&4	138		Steel Pole	0.02		2	336.4 KCM ACSR
136	CONWAY	MERAMEC_3&4	138		Steel Pole		0.06	2	556.5 KCM AAC
137	CONWAY	MERAMEC_3&4	138		Steel Pole	2.57	2.91	2	954 KCM ACSR
138	CONWAY	MERAMEC_3&4	138		Wood Pole	0.06		1	336.4 KCM ACSR
139	CONWAY	MERAMEC_3&4	138		Wood Pole	0.02		1	556.5 KCM AAC

140	MERAMEC	RIVERMINES_1&2	138		Lattice Tower	1.03	1.07	1	795 KCM I ACSR
141	MERAMEC	RIVERMINES_1&2	138		Lattice Tower	0.47	0.47	2	954 KCM I ACSR
142	MERAMEC	RIVERMINES_1&2	138		Steel Pole	2.58	2.90	2	2156 KCM ACSR
143	MERAMEC	RIVERMINES_1&2	138		Steel Pole	0.50		2	795 KCM I ACSR
144	MERAMEC	RIVERMINES_1&2	138		Steel Pole	0.31	0.68	2	795 KCM I ACSS
145	MERAMEC	RIVERMINES_1&2	138		Wood Pole	7.11		1	2156 KCM ACSR
146	MERAMEC	RIVERMINES_1&2	138		Wood Pole	79.41		1	795 KCM I ACSR
147	MERAMEC	RIVERMINES_1&2	138		Wood Pole	2.50		1	795 KCM I ACSS
148	MERAMEC	RIVERMINES_1&2	138		Wood Pole	0.18		1	795 KCM I ACSS/HS
149	MERAMEC	RIVERMINES_1&2	138		Wood Pole	0.58		1	954 KCM I ACSR
150	RIVERMINES	TAUM SAUK_1&2	138		Lattice Tower	28.75	28.75	2	477 KCM I ACSR
151	RIVERMINES	TAUM SAUK_1&2	138		Wood Pole	2.41		1	477 KCM I ACSR
152	MONTGOMERY	OVERTON_5	345		Lattice Tower	1.08		1	795 KCM I ACSR
153	MONTGOMERY	OVERTON_5	345		Steel Pole	0.04		1	2156 KCM ACSR
154	MONTGOMERY	OVERTON_5	345		Steel Pole	0.17		1	795 KCM I ACSR
155	MONTGOMERY	OVERTON_5	345		Wood Pole	62.58		1	795 KCM I ACSR
156	CAHOKIA	CENTRAL_WATSON_1&2	138		Lattice Tower	0.05		1	2156 KCM ACSR
157	CAHOKIA	CENTRAL_WATSON_1&2	138		Lattice Tower		0.13	2	954 KCM I AA
158	CAHOKIA	CENTRAL_WATSON_1&2	138		Lattice Tower	0.02		2	954 KCM I ACSR
159	CAHOKIA	CENTRAL_WATSON_1&2	138		Lattice Tower	8.55	3.19	2	954 KCM I ACSS
160	CAHOKIA	CENTRAL_WATSON_1&2	138		Steel Pole		8.19	2	2156 KCM ACSR
161	CAHOKIA	CENTRAL_WATSON_1&2	138		Steel Pole		0.04	2	954 KCM I AA
162	CAHOKIA	CENTRAL_WATSON_1&2	138		Steel Pole	0.04		2	954 KCM I ACSR
163	CAHOKIA	CENTRAL_WATSON_1&2	138		Steel Pole	0.06	0.62	2	954 KCM I ACSS
164	PAGE	MASON	138		Lattice Tower	0.01		2	1414 KCM AAC

165	PAGE	MASON	138		Lattice Tower		0.01	2	1590 KCM AAC
166	PAGE	MASON	138		Lattice Tower	8.99	8.99	2	2156 KCM ACSR
167	PAGE	MASON	138		Lattice Tower	9.52	9.53	2	664.8 KCM ACSS/TW
168	PAGE	MASON	138		Steel Pole	2.86	2.86	2	2156 KCM ACSR
169	PAGE	MASON	138		Steel Pole		0.95	2	556.5 KCM AAC
170	PAGE	MASON	138		Steel Pole	0.08	0.08	2	664.8 KCM ACSS/TW
171	PAGE	MASON	138		Wood Pole	2.50		1	556.5 KCM AAC
172	PAGE	MASON	138		Wood Pole	0.01		1	556.5 KCM ACSR
173	PAGE	MASON	138		Wood Pole	0.08		1	664.8 KCM ACSS/TW
174	(B) CALLAWAY	BLAND_1&2	345		Lattice Tower	31.79		2	1590 KCM ACSR
175	SIOUX	MALINE_3&4	138		Lattice Tower	15.79	15.59	2	2156 KCM ACSR
176	SIOUX	MALINE_3&4	138		Lattice Tower		0.03	2	336.4 KCM ACSR
177	SIOUX	MALINE_3&4	138		Steel Pole	0.07	0.08	2	2156 KCM ACSR
178	SIOUX	MALINE_3&4	138		Wood Pole	0.18		1	336.4 KCM ACSR
179	MASON	LABADIE_3&4	345		Lattice Tower	24.20	24.42	2	954 KCM ACSR
180	MASON	LABADIE_3&4	345		Wood Pole	0.19		1	954 KCM ACSR
181	LABADIE	GRAY SUMMIT_3	138		Steel Pole	0.12		1	336.4 KCM ACSR
182	LABADIE	GRAY SUMMIT_3	138		Wood Pole	5.58		1	336.4 KCM ACSR
183	LABADIE	TYSON_1&2	345		Lattice Tower	14.22	14.66	2	954 KCM ACSR
184	LABADIE	TYSON_1&2	345		Steel Pole	15.68	15.73	2	954 KCM ACSR
185	LABADIE	TYSON_1&2	345		Wood Pole	0.42		1	954 KCM ACSR
186	LABADIE	FRANKS_3	345		Lattice Tower	2.23		2	954 KCM ACSR
187	LABADIE	FRANKS_3	345		Steel Pole	0.33		1	795 KCM ACSR
188	LABADIE	FRANKS_3	345		Steel Pole	1.15		2	954 KCM ACSR
189	LABADIE	FRANKS_3	345		Wood Pole	36.67		1	795 KCM ACSR

190	LABADIE	FRANKS_3	345		Wood Pole	44.86		1	954 KCM ACSR
191	MONTGOMERY	CALLAWAY_7&8	345		Lattice Tower	23.39	23.41	2	1590 KCM ACSR
192	CALLAWAY	FRANKS	345		Lattice Tower		6.73	2	1590 KCM ACSR
193	CALLAWAY	FRANKS	345		Lattice Tower		0.02	2	954 KCM ACSS
194	CALLAWAY	FRANKS	345		Steel Pole		0.03	2	1590 KCM ACSR
195	CALLAWAY	FRANKS	345		Wood Pole	16.75		1	954 KCM ACSS
196	LOOSE CREEK	FRANKS	345		Wood Pole	37.58		1	954 KCM ACSS
197	MIDRIVERS SUPPLY		161			0.03		1	954 KCM ACSS
198	RUSH ISLAND	TYSON_1&2	345		Lattice Tower	31.37	31.36	2	954 KCM ACSR
199	RUSH ISLAND	TYSON_1&2	345		Steel Pole	1.54	1.49	2	954 KCM ACSR
200	RUSH ISLAND	TYSON_1&2	345		Wood Pole	1.21		1	954 KCM ACSR
201	MARIOSIA DELTA	APACHE FLATS	161		Steel Pole	0.93		1	954 KCM ACSR
202	MARIOSIA DELTA	APACHE FLATS	161		Wood Pole	19.83		1	954 KCM ACSR
203	LOOSE CREEK	MARIOSIA DELTA	345		Steel Pole	1.07		1	954 KCM ACSS
204	LOOSE CREEK	MARIOSIA DELTA	345		Wood Pole	9.65		1	954 KCM ACSS
205	GUTHRIE	MARIOSIA DELTA	161		Lattice Tower	0.82		1	556.5 KCM ACSR
206	GUTHRIE	MARIOSIA DELTA	161		Steel Pole	0.41		1	954 KCM ACSR
207	GUTHRIE	MARIOSIA DELTA	161		Wood Pole	13.30		1	556.5 KCM ACSR
208	GUTHRIE	MARIOSIA DELTA	161		Wood Pole	3.46		1	954 KCM ACSR
209	THOMAS HILL	ADAIR_1	161		Wood Pole	44.33		1	954 KCM ACSR
210	LABADIE	MONTGOMERY_4	345		Lattice Tower		3.09	2	954 KCM ACSR
211	LABADIE	MONTGOMERY_4	345		Steel Pole		1.15	2	954 KCM ACSR
212	LABADIE	MONTGOMERY_4	345		Wood Pole	45.99		1	954 KCM ACSR
213	ESSEX	STODDARD	161		Wood Pole	0.04		1	
214	ESSEX	STODDARD	161		Wood Pole	0.02		1	795 KCM ACSR
215	APPANOOSE	ADAIR	161		Steel Pole	30.65		2	1192.5 KCMILAC

216	APPANOOSE	ADAIR	161		Wood Pole	1.35		1	1192.5 KCMIL ACSR
217	CLARK	FLETCHER_PILOT KNOB	161		Steel Pole	0.79		1	636 KCMIL ACSR
218	CLARK	FLETCHER_PILOT KNOB	161		Wood Pole	0.04		1	1192.5 KCMIL ACSR/HS
219	CLARK	FLETCHER_PILOT KNOB	161		Wood Pole	0.29		1	1192.5 KCMIL ACSS/HS
220	CLARK	FLETCHER_PILOT KNOB	161		Wood Pole	3.16		1	336.4 KCMIL ACSR
221	CLARK	FLETCHER_PILOT KNOB	161		Wood Pole	0.35		1	556.5 KCMIL ACSS/HS
222	CLARK	FLETCHER_PILOT KNOB	161		Wood Pole	58.34		1	636 KCMIL ACSR
223	FLETCHER	PILOT KNOB_2	161		Wood Pole	13.05		1	336.4 KCMIL ACSR
224	FLETCHER	PILOT KNOB_2	161		Wood Pole	18.13		1	636 KCMIL ACSR
225	FLETCHER	SWEET WATER_3	161		Wood Pole	9.35		1	954 KCMIL ACSR
226	SIOUX	MASON_7&8	138		Lattice Tower	5.77	5.64	2	954 KCMIL ACSR
227	SIOUX	MASON_7&8	138		Steel Pole		0.07	2	2156 KCMIL ACSS
228	SIOUX	MASON_7&8	138		Steel Pole		3.82	2	2156 KCMIL SSAC
229	SIOUX	MASON_7&8	138		Steel Pole		0.02	2	556.5 KCMIL AAC
230	SIOUX	MASON_7&8	138		Steel Pole	15.68	15.66	2	954 KCMIL ACSR
231	SIOUX	MASON_7&8	138		Wood Pole	0.08		1	2156 KCMIL SSAC
232	SIOUX	MASON_7&8	138		Wood Pole	2.00		1	556.5 KCMIL AAC
233	SIOUX	MASON_7&8	138		Wood Pole	1.54		1	954 KCMIL ACSR
234	SIOUX	ROXFORD_5	345		Lattice Tower	1.11		1	954 KCMIL ACSR
235	SIOUX	ROXFORD_5	345		Steel Pole	0.66		1	954 KCMIL ACSR
236	SIOUX	ROXFORD_5	345		Wood Pole	10.47		1	954 KCMIL ACSR
237	MARSHALL	TYSON_1&2	138		Lattice Tower	5.16	5.16	2	2156 KCMIL ACSR
238	MARSHALL	TYSON_1&2	138		Steel Pole	2.01	2.04	2	2156 KCMIL ACSR
239	HIGHWAY N SUB SUPPLY		161		Steel Pole	0.63	0.63	2	795 KCMIL ACSR
240	MARSHALL	LAKESHIRE_4	138		Steel Pole	8.35		2	2156 KCMIL ACSR

241	CAPE	WEDEKIND_2	161		Steel Pole	0.83		1	954 KCM ACSR
242	CAPE	WEDEKIND_2	161		Wood Pole	0.14		1	795 KCM ACSR
243	CAPE	WEDEKIND_2	161		Wood Pole	18.24		1	954 KCM ACSR
244	MAURER LAKE	CARROLTON (KCPL)_4	161		Steel Pole	0.11		1	556.5 KCM ACSR
245	MAURER LAKE	CARROLTON (KCPL)_4	161		Wood Pole	3.05		1	556.5 KCM ACSR
246	ROCKWOOD	BIG RIVER	138		Steel Pole	1.33		1	795 KCM ACSS
247	ROCKWOOD	BIG RIVER	138		Wood Pole	9.91		1	795 KCM ACSS
248	CAPE	SIKESTON	161		Steel Pole	0.57		1	954 KCM ACSR
249	CAPE	SIKESTON	161		Steel Pole	1.49		2	1192.5 KCMIL AC
250	CAPE	SIKESTON	161		Wood Pole	34.23		1	954 KCM ACSR
251	CAPE	SIKESTON	161		Wood Pole	0.17		1	1192.5 KCMIL AC
252	CAPE	BERNTIE	161		Wood Pole	12.21		1	336.4 KCM ACSR
253	CAPE	BERNTIE	161		Wood Pole	41.67		1	954 KCM ACSR
254	MASON	MCCLAY	138		Lattice Tower	0.93		1	1192.5 KCMIL SS
255	MASON	MCCLAY	138		Steel Pole	9.66		1	1192.5 KCMIL SS
256	MASON	MCCLAY	138		Steel Pole	1.08		1	954 KCM ACSR
257	MARSHALL	HUNTER	138		Steel Pole	4.40		2	1192.5 KCMIL AC
258	MARSHALL	HUNTER	138		Steel Pole	4.21		1	1192.5 KCMIL SS
259	MISSOURI CITY(KCPL)	MAUER LAKE	161		Steel Pole	0.11		1	556.5 KCM ACSR
260	MISSOURI CITY(KCPL)	MAUER LAKE	161		Wood Pole	2.97		1	556.5 KCM ACSR
261	RUSH ISLAND	BALDWIN_4585	345		Lattice Tower	1.46		1	954 KCM ACSS
262	LUTESVILLE	NEW CAPE 345kV	345		Steel Pole	1.25		1	954 KCM ACSS
263	LUTESVILLE	NEW CAPE 345kV	345		Wood Pole	11.44		1	954 KCM ACSS
264	ROCKWOOD	GRAY SUMMIT_3&4	138		Lattice Tower	10.78	10.78	2	954 KCM ACSR
265	ROCKWOOD	GRAY SUMMIT_3&4	138		Wood Pole	0.31		1	954 KCM ACSR

266	MILLER	ZION	161		Wood Pole	18.80		1	795 KCM ACSR
267	SPALDING	FINN	161		Steel Pole	3.09		1	1192.5 KCMIL AC
268	SPALDING	FINN	161		Wood Pole	6.30		1	477 KCM ACSR
269		TOTAL EXPENSES							
36	TOTAL					2,475.56	611.93	377	

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: TransmissionLineStartPoint
The following footnote applies to columns (a), (b), and (c) of the Callaway Sub: Line is 50% owned by Union Electric Company and 50% owned by Associated Electric Cooperative. Improvements and expenses are accumulated by Union Electric Company and 50% is billed to Associated Electric; transmission line O&M and capital accounts are affected. Associated Electric Cooperative is not affiliated with Union Electric Company.
(b) Concept: SizeOfConductorAndMaterial
Size of Conductor (column i) is stated in Thousand Circular Mills or AWG.
(c) Concept: ConstructionAndOtherCostsTransmissionLines
Construction and Other Costs (column k) include damage and clearing cost per FERC Order No. 366.

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43													
44	TOTAL		0		0		0		0				

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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SUBSTATIONS

- Report below the information called for concerning substations of the respondent as of the end of the year.
- Substations which serve only one industrial or street railway customer should not be listed below.
- Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character shown.
- Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended to function the capacities reported for the individual stations in column (f).
- Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
- Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole owner equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than the name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Transformers (h)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)			
1	^(a) BOOMTOWN PP SWITCHYARD	^(a) Transmission	Unattended	138.00					
2	CALLAWAY PP SWITCHYARD	Transmission	Unattended	345.00					
3	CASS COUNTY PP SWITCHYARD	Transmission	Unattended	138.00					
4	HIGH PRAIRIE WIND NORTH PP SWITCHYARD	Transmission	Unattended	345.00					
5	HIGH PRAIRIE WIND SOUTH PP SWITCHYARD	Transmission	Unattended	345.00					
6	HUCK FINN PP SWITCHYARD	Transmission	Unattended	345.00					
7	LABADIE PP SWITCHYARD	Transmission	Unattended	345.00					
8	MERAMEC PP SWITCHYARD	Transmission	Unattended	138.00					
9	OSAGE PP SWITCHYARD	Transmission	Unattended	138.00					
10	ATCHINSON PP SWITCHYARD	Transmission	Unattended	345.00					
11	RUSH ISLAND PP SWITCHYARD	Transmission	Unattended	345.00					
12	SIOUX PP SWITCHYARD	Transmission	Unattended	345.00	138.00		700	1	
13	TAUM SAUK PP SWITCHYARD	Transmission	Unattended	138.00					
14	BUGLE - Switching Sub - 1	Transmission	Unattended	138.00					
15	BUGLE - Switching Sub - 2	Transmission	Unattended	138.00					
16	BULLION - Switching Sub	Transmission	Unattended	161.00					
17	BURNS - Switching Sub	Transmission	Unattended	345.00					
18	CAPE - Switching Sub	Transmission	Unattended	161.00					
19	^(b) FINN - Switching Sub	Transmission	Unattended	161.00					
20	GALENA - Switching Sub	Transmission	Unattended	161.00					

21	HARLEY - Switching Sub	Transmission	Unattended	161.00					
22	LUTESVILLE - Switching Sub	Transmission	Unattended	345.00					
23	STODDARD - Switching Sub	Transmission	Unattended	161.00					
24	BELLEAU	Transmission	Unattended	345.00	138.00		560	1	
25	BLAND	Transmission	Unattended	345.00	138.00		560	1	
26	CLARK	Transmission	Unattended	161.00	138.00	7.00	300	1	
27	DARDENNE - 1	Transmission	Unattended	161.00	138.00		280	1	
28	DARDENNE - 2	Transmission	Unattended	161.00	138.00	5.00	150	1	
29	DARDENNE - 3	Transmission	Unattended	161.00	138.00	7.00	168	1	
30	DARDENNE - 4	Transmission	Unattended	161.00	138.00		300		
31	FREDERICKTOWN - 1	Transmission	Unattended	161.00	138.00		300	1	
32	GRAY SUMMIT - 1	Transmission	Unattended	345.00	138.00		1120	2	
33	GRAY SUMMIT - 2	Transmission	Unattended	345.00	138.00		560		
34	HERITAGE	Transmission	Unattended	345.00	161.00		560	1	
35	JOACHIM	Transmission	Unattended	345.00	138.00		560	1	
36	KELSO - 1	Transmission	Unattended	345.00	161.00		450	1	
37	KELSO - 2	Transmission	Unattended	345.00	161.00		560	1	
38	LAKESHIRE	Transmission	Unattended	138.00					
39	LOOSE CREEK	Transmission	Unattended	345.00					
40	MARIOSIA DELTA	Transmission	Unattended	345.00	161.00		450	1	
41	MASON -1	Transmission	Unattended	345.00	138.00		1260	2	
42	MASON - 2	Transmission	Unattended	345.00	138.00	14.00	560	1	
43	MAURER LAKE	Transmission	Unattended	161.00					
44	MILLER	Transmission	Unattended	161.00	138.00		300	1	
45	MONTGOMERY	Transmission	Unattended	345.00	161.00		560	1	
46	OVERTON	Transmission	Unattended	345.00	161.00		560	1	
47	SPENCER CREEK SW STA	Transmission	Unattended	345.00					
48	ST FRANCOIS	Transmission	Unattended	345.00	138.00		1260	2	
49	TYSON	Transmission	Unattended	345.00	138.00		1820	3	
50	VIADUCT	Transmission	Unattended	161.00	115.00		83	1	
51	WEDEKIND 161KV CAP BANKS	Transmission	Unattended	161.00					
52	WILDWOOD	Transmission	Unattended	345.00	138.00	13.00	1260	2	
53	BLAND - Switching Sub	Distribution	Unattended	34.00					
54	FRANCIS - Switching Sub	Distribution	Unattended	34.00					
55	HANNIBAL WEST - Switching Sub	Distribution	Unattended	161.00					
56	JEFF CITY - Switching Sub	Distribution	Unattended	69.00					

57	LIBERTY - Switching Sub	Distribution	Unattended	69.00					
58	MLK - Switching Sub	Distribution	Unattended	14.00					
59	TAUM SAUK - Switching Sub	Distribution	Unattended	34.00					
60	TOWNLEY - Switching Sub	Distribution	Unattended	34.00					
61	ADAIR	Distribution	Unattended	161.00	69.00		112		2
62	AFFTON	Distribution	Unattended	35.00	4.00		28		2
63	ALDINE	Distribution	Unattended	35.00	4.00		27		2
64	ALGANA	Distribution	Unattended	35.00	12.00		45		2
65	ALLEN	Distribution	Unattended	35.00	4.00		14		1
66	APACHE FLATS	Distribution	Unattended	161.00	69.00		84		1
67	ARNOLD - 1	Distribution	Unattended	138.00	35.00		336		3
68	ARNOLD - 2	Distribution	Unattended						
69	ARROWHEAD	Distribution	Unattended	35.00	12.00		22		1
70	ASHBY	Distribution	Unattended	35.00	4.00		14		1
71	ASHLEY	Distribution	Unattended	138.00	12.00		168		3
72	AU BON PAIN	Distribution	Unattended	69.00	12.00		14		1
73	AUBURN	Distribution	Unattended	35.00	12.00		14		1
74	AUDRAIN	Distribution	Unattended	69.00	35.00		22		1
75	AUDRAIN-12	Distribution	Unattended	69.00	12.00		14		1
76	AUDUBON	Distribution	Unattended	35.00	4.00		14		1
77	BABLER	Distribution	Unattended	138.00	35.00		224		2
78	BAILEY	Distribution	Unattended	138.00	35.00		274		3
79	BALLAS	Distribution	Unattended	35.00	12.00		67		3
80	BALTIMORE	Distribution	Unattended	35.00	4.00		14		1
81	BARRETT STATION	Distribution	Unattended	138.00	12.00		45		1
82	BARTON	Distribution	Unattended	35.00	12.00		67		3
83	BATES	Distribution	Unattended	35.00	4.00		25		2
84	BAUMGARTNER	Distribution	Unattended	138.00	35.00		224		2
85	BAXTER	Distribution	Unattended	35.00	12.00		67		3
86	BELGRADE	Distribution	Unattended	161.00	25.00		28		2
87	BELLE	Distribution	Unattended	138.00	35.00		37		1
88	BERKELEY	Distribution	Unattended	138.00	35.00		468		5
89	BERNTIE	Distribution	Unattended	161.00	35.00		56		1
90	BERRY	Distribution	Unattended	35.00	4.00		13		1
91	BIG RIVER	Distribution	Unattended	138.00	35.00		168		2
92	BISMARCK	Distribution	Unattended	35.00	12.00		11		1
93	BLACKJACK	Distribution	Unattended	35.00	12.00		45		2

94	BLAIR	Distribution	Unattended	35.00	4.00		28	2
95	BLANCHETTE	Distribution	Unattended	138.00	35.00		112	1
96	BLUE SPRINGS	Distribution	Unattended	35.00	12.00		45	2
97	BONNE TERRE	Distribution	Unattended	35.00	12.00		45	2
98	BOONSLICK	Distribution	Unattended	35.00	12.00		22	1
99	BOSCHERTOWN	Distribution	Unattended	35.00	12.00		14	1
100	BOUNDARY	Distribution	Unattended	35.00	12.00		14	1
101	BOURBEUSE	Distribution	Unattended	35.00	12.00		45	2
102	BOWLES	Distribution	Unattended	35.00	12.00		45	2
103	BOWLING GREEN	Distribution	Unattended	35.00	12.00		14	1
104	BOYD BRANCH	Distribution	Unattended	138.00	12.00		34	1
105	BOYLE	Distribution	Unattended	35.00	12.00		45	2
106	BRENNEN	Distribution	Unattended	138.00	12.00		67	2
107	BRENTWOOD	Distribution	Unattended	35.00	4.00		25	2
108	BROOKFIELD	Distribution	Unattended	69.00	12.00		44	2
109	BROWN	Distribution	Unattended	35.00	4.00		28	2
110	BRUSH CREEK	Distribution	Unattended	35.00	12.00		36	2
111	BRUSHY CREEK	Distribution	Unattended	161.00	35.00		37	1
112	BUFFALO	Distribution	Unattended	69.00	35.00		35	2
113	BUFFALO-12	Distribution	Unattended	35.00	12.00		14	1
114	BULWER	Distribution	Unattended	35.00	12.00		45	2
115	BUTCHER BRANCH	Distribution	Unattended	35.00	12.00		22	1
116	BYRNESVILLE	Distribution	Unattended	35.00	12.00		45	2
117	CALIFORNIA	Distribution	Unattended	161.00	35.00		93	2
118	CALLAHAN	Distribution	Unattended	35.00	12.00		14	1
119	CALUMET - 1	Distribution	Unattended	161.00	69.00		56	1
120	CALUMET - 2	Distribution	Unattended	69.00	35.00		20	1
121	CAMDEN	Distribution	Unattended	161.00	35.00		56	1
122	CANTON	Distribution	Unattended	69.00	12.00		14	1
123	CAPE ROCK	Distribution	Unattended	35.00	12.00		45	2
124	CAPE-ELM	Distribution	Unattended	35.00	4.00		13	2
125	CAPE-HWY 61	Distribution	Unattended	35.00	12.00		22	1
126	CAPE-NORTH RURAL	Distribution	Unattended	35.00	12.00		14	1
127	CARONDELET - 1	Distribution	Unattended	35.00	12.00		28	2
128	CARONDELET - 2	Distribution	Unattended	35.00	4.00		28	2
129	CARROLTON - 1	Distribution	Unattended	138.00	35.00		336	2
130	CARROLTON - 2	Distribution	Unattended	138.00	35.00		168	

131	CARSON	Distribution	Unattended	35.00	4.00		14	1
132	CARUTHERSVILLE WEST	Distribution	Unattended	35.00	12.00		11	1
133	CASS	Distribution	Unattended	35.00	4.00		42	3
134	CASTLEWOOD	Distribution	Unattended	35.00	12.00		45	2
135	CATALAN	Distribution	Unattended	35.00	4.00		14	1
136	CATAWISSA	Distribution	Unattended	35.00	12.00		36	2
137	CAVE SPRINGS	Distribution	Unattended	35.00	12.00		45	2
138	CEDAR HILL	Distribution	Unattended	35.00	12.00		45	2
139	CENTER	Distribution	Unattended	69.00	35.00		22	1
140	CENTRAL	Distribution	Unattended	138.00	35.00		336	3
141	CENTRALIA	Distribution	Unattended	69.00	35.00		22	1
142	CHARLESTON	Distribution	Unattended	161.00	35.00		56	1
143	CHARLESTON-12	Distribution	Unattended	35.00	12.00		14	1
144	CHARLESTON-MAIN	Distribution	Unattended	35.00	4.00		11	1
145	CHEROKEE	Distribution	Unattended	35.00	4.00		42	3
146	CHIPPEWA	Distribution	Unattended	35.00	4.00		42	3
147	CHOUTEAU	Distribution	Unattended	35.00	4.00		28	2
148	CLARK	Distribution	Unattended	138.00	35.00		37	1
149	CLARKSON	Distribution	Unattended	138.00	12.00		67	2
150	CLAYTON	Distribution	Unattended	35.00	4.00		28	2
151	CLAYTON-12	Distribution	Unattended	35.00	12.00		45	2
152	CLYDESDALE	Distribution	Unattended	35.00	12.00		22	1
153	COLOGNE	Distribution	Unattended	35.00	4.00		28	2
154	COLUMBUS-12	Distribution	Unattended	69.00	12.00		22	1
155	CONCORD	Distribution	Unattended	35.00	12.00		45	2
156	CONNECTICUT	Distribution	Unattended	35.00	4.00		27	2
157	CONWAY	Distribution	Unattended	138.00	35.00		400	4
158	COOL SPRINGS	Distribution	Unattended	35.00	12.00		28	2
159	COOL VALLEY	Distribution	Unattended	35.00	4.00		27	2
160	COPLEY	Distribution	Unattended	138.00	12.00		90	2
161	CRAIG	Distribution	Unattended	35.00	12.00		67	3
162	CRESTWOOD	Distribution	Unattended	35.00	12.00		45	2
163	CREVE COEUR	Distribution	Unattended	35.00	12.00		22	1
164	CROSS KEYS	Distribution	Unattended	35.00	12.00		45	2
165	DALE	Distribution	Unattended	35.00	4.00		13	1
166	DEER CREEK	Distribution	Unattended	35.00	12.00		45	2
167	DELBIDGE	Distribution	Unattended	138.00	35.00		37	1

168	DELLWOOD	Distribution	Unattended	35.00	4.00		28	2
169	DELMAR	Distribution	Unattended	35.00	4.00		28	2
170	DES PERES	Distribution	Unattended	35.00	12.00		45	2
171	DESOTO	Distribution	Unattended	35.00	12.00		45	2
172	DEXTER-THREE MILE RD	Distribution	Unattended	35.00	12.00		14	1
173	DIAMONDS	Distribution	Unattended	35.00	12.00		45	2
174	DORCAS	Distribution	Unattended	34.00	12.00		67	3
175	DORSETT	Distribution	Unattended	138.00	12.00		90	2
176	DOUGHERTY FERRY	Distribution	Unattended	35.00	12.00		28	2
177	DROSTE	Distribution	Unattended	35.00	12.00		45	2
178	DUCHESNE	Distribution	Unattended	35.00	12.00		22	1
179	DUNCAN	Distribution	Unattended	35.00	4.00		28	2
180	DUNKLIN	Distribution	Unattended	35.00	12.00		45	2
181	DUTZOW	Distribution	Unattended	35.00	12.00		14	1
182	DYER	Distribution	Unattended	35.00	4.00		28	2
183	EAGER	Distribution	Unattended	35.00	12.00		45	1
184	EARTH CITY	Distribution	Unattended	35.00	12.00		45	2
185	EAST PRAIRIE MAIN	Distribution	Unattended	35.00	4.00		11	1
186	EATHERTON	Distribution	Unattended	138.00	12.00		67	2
187	EDINA	Distribution	Unattended	69.00	35.00		22	1
188	EDMUNDSON	Distribution	Unattended	35.00	4.00		28	2
189	ELDON	Distribution	Unattended	161.00	35.00		93	2
190	ELDON-12	Distribution	Unattended	35.00	12.00		14	1
191	ELDON-JACKSON	Distribution	Unattended	35.00	12.00		11	1
192	ELLEDALE	Distribution	Unattended	35.00	4.00		28	2
193	ELLISVILLE	Distribution	Unattended	35.00	12.00		67	3
194	ELM	Distribution	Unattended	35.00	4.00		28	2
195	ELSBERRY	Distribution	Unattended	35.00	12.00		14	1
196	EMERSON	Distribution	Unattended	35.00	4.00		14	1
197	ENRIGHT	Distribution	Unattended	35.00	4.00		28	2
198	ENRIGHT-12	Distribution	Unattended	35.00	12.00		45	2
199	ESTHER	Distribution	Unattended	138.00	35.00		168	2
200	EUCLID	Distribution	Unattended	138.00	35.00		336	2
201	EUREKA	Distribution	Unattended	35.00	12.00		28	2
202	FAIRGROUNDS	Distribution	Unattended	69.00	12.00		50	2
203	FARMINGTON	Distribution	Unattended	35.00	12.00		36	2
204	FEE FEE	Distribution	Unattended	35.00	12.00		45	2

205	FEISE	Distribution	Unattended	35.00	12.00		45	2
206	FENTON	Distribution	Unattended	35.00	12.00		45	2
207	FERGUSON	Distribution	Unattended	35.00	4.00		28	2
208	FESTUS	Distribution	Unattended	35.00	12.00		45	2
209	FLETCHER - 1	Distribution	Unattended	161.00	35.00		33	1
210	FLETCHER - 2	Distribution	Unattended	69.00	35.00		20	1
211	FLINT HILL	Distribution	Unattended	35.00	12.00		45	2
212	FLORISSANT	Distribution	Unattended	138.00	12.00		78	2
213	FOLSOM	Distribution	Unattended	35.00	4.00		42	3
214	FORDER	Distribution	Unattended	35.00	12.00		45	2
215	FORISTELL	Distribution	Unattended	35.00	12.00		45	2
216	FORT ZUMWALT	Distribution	Unattended	138.00	35.00		224	2
217	FOUNTAIN LAKES	Distribution	Unattended	138.00	12.00		45	1
218	FOXBORO	Distribution	Unattended	35.00	4.00		28	2
219	FRANKLIN - 1	Distribution	Unattended	138.00	35.00		196	2
220	FRANKLIN - 2	Distribution	Unattended	161.00	35.00		84	1
221	FREDERICKTOWN	Distribution	Unattended	138.00	35.00		25	1
222	FRIEDENS	Distribution	Unattended	35.00	12.00		22	1
223	FROG HOLLOW	Distribution	Unattended	69.00	12.00		45	2
224	FRONTENAC	Distribution	Unattended	35.00	12.00		45	2
225	FROST	Distribution	Unattended	35.00	4.00		14	1
226	GARDNER	Distribution	Unattended	69.00	35.00		37	1
227	GASCO - 1	Distribution	Unattended	138.00	35.00		37	1
228	GASCO - 2	Distribution	Unattended	138.00	69.00		22	1
229	GERALD	Distribution	Unattended	69.00	35.00		20	1
230	GERALDINE	Distribution	Unattended	35.00	4.00		28	2
231	GIMBLIN	Distribution	Unattended	35.00	4.00		28	2
232	GLENDALE	Distribution	Unattended	35.00	4.00		28	2
233	GLENWOOD	Distribution	Unattended	35.00	12.00		21	2
234	GOODFELLOW	Distribution	Unattended	35.00	4.00		14	1
235	GORDONVILLE	Distribution	Unattended	35.00	12.00		22	1
236	GRANDVIEW	Distribution	Unattended	35.00	4.00		27	2
237	GRAND GLAZE	Distribution	Unattended	35.00	12.00		45	2
238	GRANITEVILLE	Distribution	Unattended	35.00	12.00		11	1
239	GRATIOT - 1	Distribution	Unattended	138.00	12.00		168	3
240	GRATIOT - 2	Distribution	Unattended	138.00	12.00		84	
241	GRAVOIS	Distribution	Unattended	35.00	4.00		27	2

242	GROBY	Distribution	Unattended	35.00	4.00		28	2
243	GUSTINE	Distribution	Unattended	35.00	4.00		27	2
244	GUTHRIE	Distribution	Unattended	161.00	69.00		84	1
245	HALL STREET	Distribution	Unattended	138.00	35.00		336	3
246	HALLS FERRY	Distribution	Unattended	35.00	4.00		27	2
247	HAMPTON	Distribution	Unattended	35.00	4.00		28	2
248	HANLEY	Distribution	Unattended	35.00	4.00		42	3
249	HAPPY SAC	Distribution	Unattended	35.00	12.00		22	1
250	HARRISON	Distribution	Unattended	69.00	35.00		37	1
251	HARRISON-14	Distribution	Unattended	69.00	12.00		22	1
252	HARVESTER	Distribution	Unattended	35.00	12.00		45	2
253	HAYTI	Distribution	Unattended	161.00	35.00		112	2
254	HAZELWOOD	Distribution	Unattended	35.00	12.00		45	2
255	HEEGE	Distribution	Unattended	35.00	4.00		14	1
256	HEINTZ	Distribution	Unattended	35.00	12.00		45	2
257	HEMATITE	Distribution	Unattended	35.00	12.00		14	1
258	HEMSATH	Distribution	Unattended	35.00	12.00		45	2
259	HICKORY-12	Distribution	Unattended	35.00	12.00		45	2
260	HICKORY	Distribution	Unattended	35.00	4.00		28	2
261	HIGH RIDGE	Distribution	Unattended	35.00	12.00		45	2
262	HIGHWAY 5	Distribution	Unattended	69.00	35.00		13	1
263	HIGHWAY N	Distribution	Unattended	161.00	35.00		224	2
264	HILLSBORO	Distribution	Unattended	35.00	12.00		42	2
265	HITT	Distribution	Unattended	161.00	35.00		56	1
266	HOLT'S SUMMIT	Distribution	Unattended	69.00	12.00		14	1
267	HOOVER	Distribution	Unattended	35.00	4.00		14	1
268	HORINE	Distribution	Unattended	35.00	12.00		27	2
269	HORSESHOE BEND	Distribution	Unattended	35.00	12.00		45	2
270	HOUSE SPRINGS	Distribution	Unattended	35.00	12.00		36	2
271	HOWERSHELL	Distribution	Unattended	35.00	12.00		22	1
272	HOWE	Distribution	Unattended	35.00	12.00		45	2
273	HUDLIN PARK	Distribution	Unattended	35.00	4.00		42	3
274	HUMBOLDT	Distribution	Unattended	35.00	4.00		13	1
275	HUNTER	Distribution	Unattended	138.00	35.00		486	3
276	HUSTER	Distribution	Unattended	138.00	35.00		312	3
277	IDLEWOOD	Distribution	Unattended	69.00	12.00		22	1
278	IMPERIAL	Distribution	Unattended	35.00	12.00		36	2

279	INDEPENDENCE	Distribution	Unattended	35.00	4.00		28	2
280	JACKSON	Distribution	Unattended	35.00	4.00		28	2
281	JAMESTOWN	Distribution	Unattended	35.00	12.00		28	2
282	JAMIESON	Distribution	Unattended	35.00	4.00		28	2
283	JEFF CITY ELM ST-12	Distribution	Unattended	69.00	12.00		45	2
284	JENNINGS	Distribution	Unattended	35.00	4.00		42	3
285	JONESBURG-4	Distribution	Unattended	35.00	12.00		14	1
286	JUNCTION	Distribution	Unattended	35.00	12.00		13	1
287	JUNGERMAN	Distribution	Unattended	35.00	12.00		42	2
288	KELLWOOD	Distribution	Unattended	35.00	12.00		29	2
289	KINGDOM CITY	Distribution	Unattended	69.00	12.00		11	2
290	KINGSBURY (NEW)	Distribution	Unattended	35.00	4.00		28	2
291	KINLOCH	Distribution	Unattended	35.00	4.00		14	1
292	KIRKSVILLE	Distribution	Unattended	35.00	12.00		22	1
293	LACKLAND	Distribution	Unattended	35.00	12.00		45	2
294	LACLEDE	Distribution	Unattended	35.00	4.00		27	2
295	LADDONIA EAST	Distribution	Unattended	69.00	35.00		22	1
296	LAKE OZARK	Distribution	Unattended	35.00	12.00		28	2
297	LAKESHIRE	Distribution	Unattended	138.00	35.00		504	3
298	LAKESIDE	Distribution	Unattended	138.00	35.00		168	2
299	LAMBERT	Distribution	Unattended	35.00	4.00		28	2
300	LANDWEHR	Distribution	Unattended	35.00	4.00		14	1
301	LARIMORE	Distribution	Unattended	35.00	12.00		45	2
302	LATHROP	Distribution	Unattended	161.00	69.00		33	1
303	LEADINGTON	Distribution	Unattended	35.00	12.00		28	2
304	LEAH	Distribution	Unattended	35.00	12.00		14	1
305	LEFARTH	Distribution	Unattended	35.00	12.00		45	2
306	LEGION TRAILS	Distribution	Unattended	35.00	12.00		22	1
307	LEMAY	Distribution	Unattended	138.00	35.00		336	2
308	LENOX	Distribution	Unattended	35.00	4.00		28	2
309	LEONA	Distribution	Unattended	35.00	4.00		11	1
310	LESPERANCE	Distribution	Unattended	35.00	4.00		41	3
311	LILAC	Distribution	Unattended	35.00	4.00		27	2
312	LINCOLN	Distribution	Unattended	161.00	35.00		224	2
313	LINN CREEK	Distribution	Unattended	35.00	12.00		14	1
314	LOCKWOOD	Distribution	Unattended	35.00	4.00		28	2
315	LONEDELL	Distribution	Unattended	35.00	12.00		45	2

316	LOUGHBOROUGH	Distribution	Unattended	35.00	4.00		26	2
317	LOY MARTIN	Distribution	Unattended	161.00	12.00		22	1
318	LUXEBURG	Distribution	Unattended	35.00	4.00		25	2
319	MACKLIND	Distribution	Unattended	35.00	4.00		28	2
320	MADISON-12	Distribution	Unattended	35.00	12.00		45	2
321	MAGNOLIA	Distribution	Unattended	35.00	4.00		25	2
322	MALINE	Distribution	Unattended	138.00	35.00		424	4
323	MANCHESTER	Distribution	Unattended	35.00	12.00		45	2
324	MANOR	Distribution	Unattended	35.00	4.00		14	1
325	MAPLEWOOD	Distribution	Unattended	35.00	4.00		28	2
326	MARION	Distribution	Unattended	161.00	35.00		74	2
327	MARK TWAIN	Distribution	Unattended	35.00	12.00		27	2
328	MARSHALL	Distribution	Unattended	138.00	35.00		448	4
329	MARYLAND	Distribution	Unattended	35.00	4.00		14	2
330	MARYVILLE	Distribution	Unattended	35.00	12.00		45	2
331	MASON-34	Distribution	Unattended	138.00	35.00		224	2
332	MAURER LAKE - 1	Distribution	Unattended	161.00	69.00		93	2
333	MAURER LAKE - 2	Distribution	Unattended	69.00	35.00		22	1
334	MAXVILLE	Distribution	Unattended	35.00	12.00		45	2
335	MAY ROAD	Distribution	Unattended	35.00	12.00		45	2
336	MCCAUSLAND	Distribution	Unattended	35.00	4.00		39	3
337	MCCLAY	Distribution	Unattended	138.00	35.00		224	2
338	MCCLEARY	Distribution	Unattended	69.00	35.00		28	1
339	MCCLEARY-12	Distribution	Unattended	69.00	12.00		14	1
340	MCCLUER	Distribution	Unattended	35.00	12.00		45	2
341	MCKELVEY	Distribution	Unattended	35.00	12.00		45	2
342	MCKINLEY ST	Distribution	Unattended	35.00	12.00		45	2
343	MCKNIGHT	Distribution	Unattended	35.00	4.00		28	2
344	MCKNIGHT-12	Distribution	Unattended	35.00	12.00		22	1
345	MCPHERSON	Distribution	Unattended	35.00	4.00		28	2
346	META	Distribution	Unattended	138.00	25.00		28	2
347	MEXICO	Distribution	Unattended	69.00	35.00		37	1
348	MEXICO ROAD	Distribution	Unattended	35.00	12.00		45	2
349	MID RIVERS	Distribution	Unattended	161.00	12.00		90	2
350	MID VALLEY	Distribution	Unattended	35.00	12.00		22	1
351	MIDLAND	Distribution	Unattended	35.00	4.00		28	2
352	MIDTOWN	Distribution	Unattended	35.00	4.00		13	2

353	MINER	Distribution	Unattended	161.00	35.00		84	1
354	MINER-12	Distribution	Unattended	35.00	12.00		14	2
355	MOBERLY	Distribution	Unattended	161.00	69.00		168	2
356	MONTGOMERY-69	Distribution	Unattended	161.00	69.00		112	2
357	MOREAU 161-12KV	Distribution	Unattended	161.00	12.00		45	1
358	MOREAU 161-69-34kV	Distribution	Unattended	161.00	69.00		84	1
359	MORGAN-4	Distribution	Unattended	69.00	4.00		13	1
360	MOSCOW MILLS	Distribution	Unattended	35.00	12.00		14	1
361	MOSS HOLLOW	Distribution	Unattended	35.00	12.00		35	2
362	MT AUBURN	Distribution	Unattended	35.00	12.00		45	2
363	MULLANPHY	Distribution	Unattended	35.00	4.00		14	1
364	MURAT	Distribution	Unattended	35.00	4.00		14	1
365	NASH ROAD	Distribution	Unattended	35.00	12.00		14	1
366	NATURAL BRIDGE	Distribution	Unattended	35.00	12.00		22	1
367	NEW BLOOMFIELD	Distribution	Unattended	69.00	12.00		14	1
368	NEW FLORENCE	Distribution	Unattended	69.00	35.00		34	1
369	NEW MELLE	Distribution	Unattended	35.00	12.00		14	1
370	NEWPORT	Distribution	Unattended	35.00	12.00		45	2
371	NEWSTEAD	Distribution	Unattended	35.00	4.00		28	2
372	NMSU	Distribution	Unattended	35.00	4.00		13	1
373	NORTH FARMINGTON	Distribution	Unattended	138.00	35.00		112	1
374	NORTH PARK	Distribution	Unattended	138.00	12.00		67	2
375	NORTHLAND	Distribution	Unattended	35.00	4.00		28	2
376	O'FALLON	Distribution	Unattended	138.00	35.00		224	2
377	O'FALLON HILLS	Distribution	Unattended	35.00	12.00		45	2
378	OAKVILLE	Distribution	Unattended	35.00	12.00		11	1
379	OLD MONROE	Distribution	Unattended	35.00	12.00		22	1
380	OLIVE	Distribution	Unattended	35.00	12.00		45	2
381	ORAN	Distribution	Unattended	161.00	35.00		56	1
382	ORCHARD GARDENS	Distribution	Unattended	138.00	12.00		67	2
383	OSAGE BEACH	Distribution	Unattended	35.00	12.00		14	1
384	OTTOVILLE	Distribution	Unattended	35.00	12.00		28	2
385	OVERTON-69	Distribution	Unattended	161.00	69.00		112	2
386	OWENSVILLE	Distribution	Unattended	35.00	12.00		14	1
387	PACIFIC	Distribution	Unattended	35.00	12.00		27	2
388	PAGE	Distribution	Unattended	138.00	35.00		336	3
389	PARK CHARLES	Distribution	Unattended	35.00	12.00		22	1

390	PARKER	Distribution	Unattended	35.00	12.00		28	2
391	PASADENA	Distribution	Unattended	35.00	4.00		28	2
392	PATTERSON	Distribution	Unattended	35.00	12.00		45	2
393	PATTONVILLE	Distribution	Unattended	35.00	12.00		67	3
394	PENO CREEK SWITCHYARD	Distribution	Unattended	161.00	12.00		333	2
395	PERSHALL	Distribution	Unattended	138.00	12.00		90	2
396	PICKERING	Distribution	Unattended	69.00	12.00		14	1
397	PIERCE	Distribution	Unattended	69.00	35.00		14	1
398	PIKE - 1	Distribution	Unattended	161.00	69.00		93	2
399	PIKE - 2	Distribution	Unattended	69.00	35.00		20	1
400	PIKE-12	Distribution	Unattended	69.00	12.00		45	2
401	PILOT KNOB	Distribution	Unattended	161.00	35.00		33	1
402	PILOT KNOB N&S	Distribution	Unattended	35.00	12.00		21	2
403	PINE LAWN	Distribution	Unattended	35.00	4.00		14	1
404	PLATTIN	Distribution	Unattended	35.00	12.00		45	2
405	PLATTSBURG	Distribution	Unattended	69.00	35.00		22	1
406	POINT PRAIRIE	Distribution	Unattended	161.00	35.00		224	2
407	POND	Distribution	Unattended	35.00	12.00		45	2
408	POPLAR	Distribution	Unattended	138.00	12.00		180	2
409	PORTAGE - 1	Distribution	Unattended	138.00	12.00		14	1
410	PORTAGE - 2	Distribution	Unattended	138.00	35.00		10	
411	PORTAGEVILLE	Distribution	Unattended	161.00	35.00		20	1
412	PORTAGEVILLE CITY	Distribution	Unattended	35.00	12.00		25	2
413	POTOMAC	Distribution	Unattended	35.00	4.00		14	1
414	POTOSI	Distribution	Unattended	35.00	12.00		45	2
415	PRAIRIE	Distribution	Unattended	35.00	4.00		27	2
416	PREWITT	Distribution	Unattended	35.00	12.00		45	2
417	PRICE	Distribution	Unattended	35.00	4.00		27	2
418	QUAD	Distribution	Unattended	35.00	12.00		28	2
419	QUAKER	Distribution	Unattended	34.00	12.00		14	1
420	RAILROAD	Distribution	Unattended	69.00	35.00		28	1
421	RAINBOW	Distribution	Unattended	69.00	12.00		14	1
422	RANDOLPH	Distribution	Unattended	35.00	12.00		14	1
423	REAVIS	Distribution	Unattended	35.00	12.00		14	1
424	RENZ	Distribution	Unattended	69.00	12.00		14	1
425	RESEARCH PARK	Distribution	Unattended	35.00	12.00		45	2
426	RICHLAND - 1	Distribution	Unattended	161.00	35.00		60	1

427	RICHLAND - 2	Distribution	Unattended	161.00	35.00		84	
428	RINGER	Distribution	Unattended	138.00	12.00		64	2
429	RIPA	Distribution	Unattended	35.00	4.00		14	1
430	RIVER ROADS	Distribution	Unattended	35.00	4.00		27	2
431	RIVERMINES	Distribution	Unattended	138.00	35.00		89	2
432	RIVERPORT	Distribution	Unattended	35.00	12.00		45	2
433	ROARK	Distribution	Unattended	69.00	35.00		28	1
434	ROBERTSON	Distribution	Unattended	35.00	12.00		45	2
435	ROCK CREEK	Distribution	Unattended	35.00	12.00		36	2
436	ROCK HILL	Distribution	Unattended	35.00	4.00		28	2
437	ROCKPORT	Distribution	Unattended	35.00	12.00		45	2
438	ROCKWOOD	Distribution	Unattended	138.00	35.00		123	2
439	ROMAINE	Distribution	Unattended	35.00	12.00		45	2
440	RUDDER	Distribution	Unattended	138.00	12.00		66	2
441	RUSSELL	Distribution	Unattended	138.00	35.00		448	3
442	SADDLE CREEK	Distribution	Unattended	138.00	35.00		112	1
443	SALT LICK	Distribution	Unattended	35.00	12.00		45	2
444	SANDY CREEK	Distribution	Unattended	138.00	35.00		224	2
445	SAPPINGTON	Distribution	Unattended	35.00	12.00		45	2
446	SCHOETTLER	Distribution	Unattended	35.00	12.00		45	2
447	SCHUESSLER	Distribution	Unattended	35.00	12.00		45	2
448	SCHUETZ	Distribution	Unattended	138.00	12.00		67	2
449	SCRUGGS	Distribution	Unattended	69.00	12.00		45	2
450	SELMA	Distribution	Unattended	138.00	35.00		84	2
451	SHACKLEFORD	Distribution	Unattended	35.00	12.00		45	2
452	SHREVE	Distribution	Unattended	35.00	4.00		14	1
453	SIGMA	Distribution	Unattended	35.00	4.00		14	1
454	SINNOCK	Distribution	Unattended	69.00	35.00		28	1
455	SINNOCK-12	Distribution	Unattended	69.00	12.00		36	2
456	SIX FLAGS	Distribution	Unattended	35.00	12.00		45	2
457	SONDERN	Distribution	Unattended	35.00	12.00		45	2
458	SOUTH BROADWAY	Distribution	Unattended	35.00	4.00		28	2
459	SOUTH VIBURNUM	Distribution	Unattended	35.00	12.00		40	1
460	SOUTH WASHINGTON	Distribution	Unattended	35.00	12.00		45	2
461	SPANISH LAKE	Distribution	Unattended	35.00	12.00		14	1
462	SPARKS	Distribution	Unattended	69.00	12.00		45	2
463	SPRING FOREST	Distribution	Unattended	35.00	12.00		36	2

464	SPRINGFIELD	Distribution	Unattended	35.00	12.00		14	1
465	ST ALBANS	Distribution	Unattended	35.00	12.00		14	1
466	ST ANN	Distribution	Unattended	35.00	12.00		22	1
467	ST CHARLES	Distribution	Unattended	35.00	12.00		45	2
468	ST CLAIR	Distribution	Unattended	35.00	12.00		45	2
469	ST JOHN	Distribution	Unattended	35.00	4.00		28	2
470	ST LOUIS RD	Distribution	Unattended	69.00	12.00		22	1
471	STEELE	Distribution	Unattended	35.00	12.00		14	1
472	STL INTERNATIONAL	Distribution	Unattended	35.00	4.00		28	2
473	STRATMAN	Distribution	Unattended	35.00	4.00		27	2
474	STRINGTOWN	Distribution	Unattended	69.00	12.00		14	1
475	SULPHUR	Distribution	Unattended	35.00	4.00		14	1
476	SUNSET	Distribution	Unattended	35.00	12.00		45	2
477	TAMM	Distribution	Unattended	35.00	4.00		28	2
478	TAN-TAR-A	Distribution	Unattended	35.00	12.00		45	2
479	TAUSSIG	Distribution	Unattended	35.00	12.00		45	2
480	TAYLOR	Distribution	Unattended	35.00	4.00		28	2
481	TEGELER - 1	Distribution	Unattended	138.00	35.00		112	2
482	TEGELER - 2	Distribution	Unattended	138.00	35.00		22	
483	TELEGRAPH	Distribution	Unattended	35.00	12.00		45	2
484	TENBROOK	Distribution	Unattended	35.00	12.00		45	2
485	TERRE DU LAC	Distribution	Unattended	35.00	12.00		14	1
486	TESSON	Distribution	Unattended	35.00	12.00		45	2
487	THIRTIETH STREET	Distribution	Unattended	35.00	4.00		14	1
488	TISDALE-12	Distribution	Unattended	69.00	12.00		45	2
489	TOWERS	Distribution	Unattended	35.00	12.00		22	1
490	TROJAN	Distribution	Unattended	35.00	12.00		14	1
491	TROY-14	Distribution	Unattended	35.00	12.00		45	2
492	TURKEY BEND	Distribution	Unattended	35.00	12.00		45	2
493	UNICITY	Distribution	Unattended	35.00	12.00		45	2
494	UNION	Distribution	Unattended	35.00	12.00		45	2
495	VALLES MINES	Distribution	Unattended	35.00	12.00		14	1
496	VALLEY PARK	Distribution	Unattended	35.00	12.00		45	2
497	VANDEVENTER	Distribution	Unattended	35.00	4.00		13	1
498	VERNON	Distribution	Unattended	35.00	4.00		13	1
499	VERSAILLES	Distribution	Unattended	35.00	12.00		12	1
500	VESSEL	Distribution	Unattended	138.00	35.00		84	1

501	VIADUCT - 1	Distribution	Unattended	115.00	35.00		140	2
502	VIADUCT - 2	Distribution	Unattended	161.00	35.00		84	1
503	VIBURNUM	Distribution	Unattended	161.00	35.00		37	1
504	VINITA	Distribution	Unattended	35.00	4.00		25	2
505	VISTA	Distribution	Unattended	35.00	4.00		28	2
506	WALDRON	Distribution	Unattended	35.00	4.00		14	1
507	WALLEN CREEK	Distribution	Unattended	138.00	35.00		37	1
508	WALNUT	Distribution	Unattended	35.00	12.00		28	2
509	WARNER	Distribution	Unattended	35.00	12.00		14	1
510	WARRENTON	Distribution	Unattended	161.00	35.00		112	2
511	WARSON	Distribution	Unattended	138.00	35.00		436	4
512	WATERFORD	Distribution	Unattended	35.00	12.00		20	1
513	WATSON	Distribution	Unattended	138.00	35.00		336	3
514	WAYLAND	Distribution	Unattended	69.00	35.00		13	2
515	WEBSTER	Distribution	Unattended	35.00	4.00		28	2
516	WEDEKIND	Distribution	Unattended	161.00	35.00		140	2
517	WEIL	Distribution	Unattended	35.00	4.00		14	1
518	WELDON SPRING	Distribution	Unattended	35.00	12.00		45	2
519	WELLSVILLE	Distribution	Unattended	69.00	35.00		22	1
520	WEST AVENUE	Distribution	Unattended	35.00	12.00		14	1
521	WEST MOSBY	Distribution	Unattended	69.00	12.00		14	1
522	WESTERN	Distribution	Unattended	35.00	4.00		13	1
523	WILD HORSE	Distribution	Unattended	35.00	12.00		45	2
524	WILDCAT HOLLOW	Distribution	Unattended	35.00	12.00		14	1
525	WILL	Distribution	Unattended	35.00	12.00		25	2
526	WINGHAVEN	Distribution	Unattended	35.00	12.00		45	2
527	WOOD HEIGHTS	Distribution	Unattended	35.00	12.00		14	1
528	WOODSMILL	Distribution	Unattended	35.00	12.00		67	3
529	WOODSON	Distribution	Unattended	35.00	4.00		28	2
530	YAEGER	Distribution	Unattended	35.00	12.00		22	1
531	YELLOW ROCK	Distribution	Unattended	35.00	12.00		22	1
532	YORKSHIRE	Distribution	Unattended	35.00	4.00		28	2
533	ZION	Distribution	Unattended	161.00	69.00		84	1
534	(c) Summary - Transmission PP Switchyard - 345	Transmission		345.00				
535	Summary - Transmission PP Switchyard - 345/138	Transmission		345.00	138.00		700	1
536	Summary - Transmission PP Switchyard - 138	Transmission		138.00				

537	Summary - Transmission Switching Sub - 345	Transmission		345.00					
538	Summary - Transmission Switching Sub - 161	Transmission		161.00					
539	Summary - Transmission Switching Sub - 138	Transmission		138.00					
540	Summary - Transmission - 345/161	Transmission		345.00	161.00		3140		6
541	Summary - Transmission - 345/138	Transmission		345.00	138.00		9520		15
542	Summary - Transmission - 161/138	Transmission		161.00	138.00		1798		6
543	Summary - Transmission - 161/115	Transmission		161.00	115.00		83		1
544	Summary - Distribution Switching Sub - 161	Distribution		161.00					
545	Summary - Distribution Switching Sub - 69	Distribution		69.00					
546	Summary - Distribution Switching Sub - 34	Distribution		34.00					
547	Summary - Distribution Switching Sub - 14	Distribution		14.00					
548	Summary - Distribution >=10MVA - 69/4	Distribution		69.00	4.00		13		1
549	Summary - Distribution >=10MVA - 69/35	Distribution		69.00	35.00		588		26
550	Summary - Distribution >=10MVA - 69/12	Distribution		69.00	12.00		653		35
551	Summary - Distribution >=10MVA - 35/4	Distribution		35.00	4.00		2734		202
552	Summary - Distribution >=10MVA - 35/12	Distribution		35.00	12.00		6694		333
553	Summary - Distribution >=10MVA - 161/69	Distribution		161.00	69.00		1115		18
554	Summary - Distribution >=10MVA - 161/35	Distribution		161.00	35.00		2132		32
555	Summary - Distribution >=10MVA - 161/25	Distribution		161.00	25.00		28		2
556	Summary - Distribution >=10MVA - 161/12	Distribution		161.00	12.00		490		6
557	Summary - Distribution >=10MVA - 138/69	Distribution		138.00	69.00		22		1
558	Summary - Distribution >=10MVA - 138/35	Distribution		138.00	35.00		10394		97
559	Summary - Distribution >=10MVA - 138/25	Distribution		138.00	25.00		28		2
560	Summary - Distribution >=10MVA - 138/12	Distribution		138.00	12.00		1618		36
561	Summary - Distribution >=10MVA - 115/35	Distribution		115.00	35.00		140		2
562	Summary - Distribution >=10MVA - 34/12	Distribution		34.00	12.00		81		4
563	Summary - Distribution < 10 MVA	Distribution					741		282

564	(d) Number of Transmission Substations - 46								
565	(e) Number of Distribution Substations >=10MVA - 467								
566	(f) Number of Distribution Substations <10MVA - 139								
567	TotalDistributionSubstationMember								
568	TotalTransmissionSubstationMember								
569	Total								

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: SubstationNameAndLocation

This footnote applies to lines 1-13, column (a):
No transformation exists at the listed substation.

(b) Concept: SubstationNameAndLocation

The Finn substation is 51% owned by Union Electric Company and 49% owned by the Missouri Joint Municipal Electric Utility Commission (MJMEUC). Improvements and expenses are accumulated by Union Electric Company and 49% is billed to MJMEUC. Union Electric Company reports only its proportionate share of substation O&M and capital balances. MJMEUC is not affiliated with Union Electric Company.

(c) Concept: SubstationNameAndLocation

Functional information is summarized utilizing nominal voltage amounts. Nominal voltages represent the following ranges:

Nominal KV _a	KV _a Range
5	1 – 7
15	12 – 15
35	30 – 37
69	67 – 72
115	115
138	135 – 145
161	160 – 165
230	230
345	345 – 353

(d) Concept: SubstationNameAndLocation

The number of transmission substations represents only substations included on this Form 1 page.

(e) Concept: SubstationNameAndLocation

The number of distribution substations represents only substations with capacities greater than or equal to 10KV_a included on this Form 1 page.

(f) Concept: SubstationNameAndLocation

The number of distribution substations represents only substations with capacities less than 10KV_a included in the last summary row above.

(g) Concept: SubstationCharacterDescription

This list includes all substations except those serving only one customer.

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2	Power Ops & Engineering	^(a) Ameren Services Company	101, 107, 108, 183, 184, 186, 418, 426, 500, 501, 502, 506, 510, 511, 512, 513, 514, 524, 535, 536, 537, 539, 541, 542, 543, 544, 545, 546, 548, 549, 550, 552, 553, 554, 557, 570, 580, 588, 807, 874, 880, 920, 921, 923, 925, 928, 930	3,576,955
3	Missouri Energy Delivery	Ameren Services Company	107, 108, 182.3, 184, 186, 253, 426, 513, 528, 532, 562, 569, 570, 580, 581, 582, 583, 584, 585, 586, 588, 590, 591, 592, 593, 594, 595, 596, 597, 598, 874, 880, 902, 903, 910, 921, 923, 925, 930, 935	4,573,013
4	Controller	Ameren Services Company	107, 143, 163, 181, 184, 426, 567, 903, 920, 921, 923, 928, 930, 931	29,138,950
5	Supply Chain	Ameren Services Company	107, 163, 426, 512, 517, 524, 530, 588, 920, 921, 923, 925, 930	1,719,346
6	Treasurer	Ameren Services Company	107, 181, 590, 903, 920, 921, 923, 928, 930	2,476,100
7	Fuel	Ameren Services Company	120	854,753

8	UE Generation - Nuclear	Ameren Services Company	107, 108, 120, 426, 517, 524, 528, 529, 530, 531, 532, 557, 570, 921, 923, 928	1,160,221
9	Corporate Strategy, Innovation, Environmental and Risk	Ameren Services Company	107, 426, 588, 590, 908, 920, 921, 923, 928, 935	3,984,437
10	Human Resources	Ameren Services Company	107, 426, 566, 593, 920, 921, 923, 926, 928, 930	12,358,578
11	Executive	Ameren Services Company	107, 426, 920, 921, 923, 930	5,766,880
12	Digital	Ameren Services Company	107, 108, 163, 183, 184, 186, 241, 426, 506, 524, 557, 566, 569, 580, 588, 590, 592, 593, 870, 874, 901, 902, 908, 920, 921, 923, 928, 930, 935	111,278,824
13	Corporate Policy, Analysis & Environmental	Ameren Services Company	107, 183, 188, 426, 566, 588, 590, 908, 920, 921, 923, 925, 928, 930	3,405,216
14	Legal, Fed Reg & Compliance	Ameren Services Company	107, 108, 181, 183, 186, 426, 549, 566, 920, 921, 923, 924, 925, 928, 930	16,879,440
15	Ameren Services Center	Ameren Services Company	107, 163, 426, 588, 901, 903, 920, 921, 923, 928, 930, 935	11,794,824
16	Missouri Strategic Initiatives	Ameren Services Company	107, 108, 184, 186, 188, 566, 580, 584, 588, 590, 591, 593, 874, 910, 920, 921, 923	4,175,891
17	Financial Services	Ameren Services Company	107, 163, 184, 524, 553, 561, 566, 593, 901, 903, 920, 921, 923, 930	2,595,227
18	Missouri Business Planning	Ameren Services Company	107, 182.3, 242, 908, 912, 921, 923, 930	750,624
19	Trans Ops Plan Policy and Reg	Ameren Services Company	107, 108, 121, 183, 184, 186, 352, 426, 511, 528, 531, 548, 549, 553, 557, 560, 561, 566, 568, 569, 570, 571, 580, 582, 588, 592, 593, 908, 920, 921, 923, 928, 930	30,163,644

20	Ameren Communications	Ameren Services Company	107, 426, 593, 908, 909, 910, 920, 921, 923, 930	4,875,106
21	Corporate Internal Audit	Ameren Services Company	107, 183, 426, 920, 921, 923, 930	1,314,904
22	Corporate Tax	Ameren Services Company	107, 183, 426, 549, 920, 921, 923, 928, 930	1,609,118
23	Missouri Gas Operations	Ameren Services Company	107, 108, 184, 426, 488, 588, 593, 807, 870, 874, 875, 878, 880, 885, 887, 892, 893, 921, 930	389,598
24	Safety, Security & Ops Oversight	Ameren Services Company	107, 108, 163, 183, 186, 506, 511, 524, 528, 539, 542, 549, 557, 566, 580, 581, 593, 920, 921, 923, 925, 935	5,473,383
25	Customer Affordability & ATO	Ameren Services Company	107, 163, 920, 921, 923, 928	919,568
26	Facilities & Property Management	Ameren Services Company	107, 108, 183, 418, 421, 506, 524, 539, 548, 549, 550, 552, 553, 557, 566, 571, 588, 598, 880, 894, 901, 920, 921, 923, 925, 931, 935	7,150,213
27	Missouri Business Services	Ameren Services Company	107, 108, 184, 506, 511, 541, 548, 557, 561, 902, 903, 920, 921, 923, 925, 928, 930, 935	697,221
28	Missouri Renewables Development & Environmental	Ameren Services Company	107, 108, 183, 253, 506, 512, 539, 549, 553, 557, 580, 902, 921, 930	1,128,470
29	Sustainability, Philanthropy & DE&I	Ameren Services Company	107, 426, 588, 920, 921, 923, 930	2,833,264
30	Ameren Cyber	Ameren Services Company	107, 183, 184, 524, 528, 532, 566, 590, 903, 920, 921, 923, 930, 935	18,413,692
31	Customer & Digital Support Services	Ameren Services Company	107, 108, 183, 184, 588, 901, 903, 910, 920, 921, 923, 928, 930	32,144,220
32	Customer Experience	Ameren Services Company	107, 186, 242, 426, 580, 588, 593, 901, 902, 903, 908, 910, 920, 921, 923	4,514,549

33	Interest	Ameren Services Company	430	3,937,271
34	Stores Inventory Transfers	Ameren Illinois Company	154	463,017
35	Engineering and Construction Support	Ameren Illinois Company	107, 549, 903, 920	571,887
36	Stores Inventory Transfers	Ameren Transmission Company of Illinois	154	6,118
19				
20	Non-power Goods or Services Provided for Affiliated			
21	Rental Income	Ameren Services Company	454, 493	30,358,896
22	Vehicle Usage by Affiliate	Ameren Services Company	184	1,321,299
23	Stores Inventory Transfers	Ameren Services Company	154	489,172
24	Laboratory Services	Ameren Illinois Company	184	611,376
25	Stores Inventory Transfers	Ameren Illinois Company	154	476,482
26	Engineering and Construction Support	Ameren Illinois Company	184, 549, 920	1,742,885
27	Stores Inventory Transfers	Ameren Transmission Company of Illinois	154	3,606,608
28	Engineering and Construction Support	Ameren Transmission Company of Illinois	184	1,051,358
42				

Name of Respondent: Union Electric Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4
FOOTNOTE DATA			

<p>(a) Concept: NameOfAssociatedAffiliatedCompany</p>
<p>Goods and services provided by Ameren Services Company are allocated via one of the following allocation methodologies:</p> <p>Direct In addition to the allocation factors listed below, appropriate direct allocations are made for costs benefiting a single Client Company or Other Client Company.</p> <p>Indirect Functional and Corporate Indirect allocations are also made to all affiliates. Indirect Costs include those costs of a general overhead basis which cannot be identified to a single Client Company or group of Client Companies.</p> <p>Operational Composite – Sales, Customers and Employees Based on equal weighting of Sales (kwh & dekatherm), number of customers, and number of employees.</p> <p>Corporate Composite Based on an equal weighting of Revenues (total), Assets (total), and Labor (total) allocation factors.</p> <p>Number of Customers Based on the number of customers at the end of the most recent calendar year.</p> <p>Number of Employees Based on the number of employees at the end of the most recent calendar year.</p> <p>Sales Based on sales volume (kwh and/or dekatherms) for the most recent calendar year.</p> <p>Labor Based on the Labor for the most recent calendar year.</p> <p>Revenues Based on revenues for the most recent calendar year.</p> <p>Total Capitalization Based on total operating company capitalization value at the end of the most recent calendar year.</p> <p>Total Assets Based on total assets at the end of the most recent calendar year.</p> <p>Gross Plant-in-Service plus Construction Work In Progress (CWIP) Based on the Gross Plant-in-Service plus CWIP at the end of the most recent calendar year.</p> <p>Construction Expenditures Based on construction expenditures for the most recent calendar year.</p> <p>Forecasted Capital Expenditures Based on the 3-year total forecast for capital expenditures, as included in Ameren's most recent board-approved capital expenditure budget.</p> <p>Forecasted Transmission Capital Expenditures Based on the 3-year total forecast for transmission capital expenditures, as included in Ameren's most recent board-approved capital expenditure budget.</p> <p>Peak Load (electric) Based on the average 12 month coincidental peak for the 12 months ending June of the prior year.</p> <p>Electric Net Generation (MWh) Based on the electric net generation (megawatt hours) at the end of the most recent calendar year.</p> <p>Current Tax Expense Based on taxes charged (income and other) for the most recent calendar year.</p> <p>Number of Vehicles Based on the number of vehicles at the end of the most recent calendar year.</p> <p>Number of General Ledger Transactions Based on number of general ledger transactions.</p> <p>Number of Accounts Payable Vouchers Based on number of accounts payable vouchers.</p> <p>Number of Active Projects Based on the number of active projects.</p> <p>Number of Major Projects Based on the number of projects greater than \$25 million.</p> <p>Number of Managed PCs Based on the number of PCs managed by Information Technology.</p> <p>Non-Fuel Expenditures Based on the dollar expenditures of non-fuel transactions.</p> <p>Computer Server Usage-Other than UNIX Based on the number of non-UNIX computer servers assigned to an operating company.</p> <p>Computer Server Usage-UNIX Based on the number of UNIX computer servers assigned to an operating company.</p>

Storage Device Usage

Based on the storage device usage by a Client Company or business segment, a ratio will be determined.

Governmental Affairs

Based on the information by Ameren's Governmental Affairs organizations as to what companies and/or business segments will be supported in the coming year.

Transmission Circuit Miles

Based on the number of transmission circuit miles in service at the end of the most recent calendar year.

Number of MISO Transmission Companies

Based on the number of companies that are Transmission Owners in MISO.

Number of Transmission Substations in Service

Based on the number of transmission substations in service at the end of the most recent calendar year.

Undivided Interest

Based on the fractional ownership of an asset, a pre-determined allocation will be calculated.

FERC FORM NO. 1 ((NEW))

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