Founded in 1852
by Sidney Davy Miller

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March 21, 2024

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Hwy.
Lansing, MI 48917

Re: Upper Peninsula Power Company
Case No.: U-21555

Dear Ms. Felice:

Enclosed for electronic filing on behalf of Upper Peninsula Power Company in regard to the above-captioned matter are the following:

1. Application;
2. Proposed Notice of Hearing;
3. Proposed Protective Order;
4. Certification of Filing Requirements;
5. Index of Exhibits
6. Direct Testimonies and Exhibits of Eric W. Stocking, Natasha L. Wonch, Nicholas E. Kates, John S. Thompson, Jay R. Ringler, Daniel J. Gervae, Virgil E. Schlorke, Jason J. Brynick, Kay L. Ryan, and Nicole E. Bell;
7. Documentation that complies with Part II of the Rate Case Filing Requirements;
8. Appearances of Sherri A. Wellman, Paul M. Collins, and Benjamin J. Holwerda; and
9. Proof of Service reflecting electronic service on intervenors in Case Nos. U-20276 and U-21286.

Pursuant to the Rate Case Filing Requirements approved by the Michigan Public Service Commission on May 18, 2023, in Case No. U-18238, the Staff case coordinator and the parties to U-20276 and U-21286 are being provided all exhibits and workpapers in native format with all formulae intact, as well as documentation addressing Part III of the Rate Case Filing Requirements via the following secure portal link:

https://filelocker.mcps.com/pickup?claimID=xVSN8ude6J6JvGmE&claimPasscode=cRczcPGRUZF7Z3FT&emailAddr=36818

You have 7 days to retrieve the drop-off; after that the link above will expire.

Claim ID:	xVSN8ude6J6JvGmE
Claim Passcode:	cRczcPGRUZF7Z3FT

As requested by the Staff case coordinator, hard copies containing this filing and workpapers will be directly served on the Commission Staff.

Sincerely,

Miller, Canfield, Paddock and Stone, P.L.C.

By: Paul Collins

Digitally signed by: Paul Collins
DN: CN = Paul Collins email = collinsp@millercanfield.com C = AD O = Miller Canfield
Date: 2024.03.21 14:37:04 -04'00'

Paul Michael Collins

PMC/vs
Enclosures
cc w/enc: Gradon R. Haehnel
Eric W. Stocking

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **UPPER PENINSULA POWER COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21555

APPLICATION

UPPER PENINSULA POWER COMPANY ("UPPCO" or the "Company") requests authority from the Michigan Public Service Commission ("Commission") to increase its rates for retail electric service, and in support thereof respectfully represents as follows:

INTRODUCTION

1. UPPCO is a public utility engaged in the generation, purchase, distribution and sale of electric energy to approximately 53,000 retail customers in 118 communities in the Upper Peninsula of Michigan. UPPCO serves certain cities, villages and townships located in the counties of Alger, Baraga, Delta, Houghton, Iron, Keweenaw, Marquette, Menominee, Ontonagon and Schoolcraft.

2. UPPCO is a corporation organized under the laws of the state of Michigan, with its principal office located at 1002 Harbor Hills Drive, Marquette, Michigan 49855, and is authorized to transact business in the state of Michigan. UPPCO is a subsidiary of Axium UP Holdings LLC ("Axium UP"). Axium UP acquired UPPCO and its parent Upper Peninsula Power Holding Company pursuant to an Order Approving Settlement Agreement issued May 26, 2021, in Case No. U-20995, in which the Commission approved, pursuant to Section 6q of 2008 PA 286, MCL 460.6q, the sale of UPPCO by Lake AIV, L.P.

3. UPPCO's retail electric service business is subject to the jurisdiction of the Commission pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1919 PA 419, as amended, MCL 460.54 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; and the Michigan Administrative Hearing System's Administrative Hearing Rules, R 792.10401 et seq. Pursuant to said statutory provisions, the Commission has power and jurisdiction to regulate UPPCO's retail electric rates for service rendered in the State of Michigan.

4. This Application is being filed in accordance with filing requirements contained in the Commission's Order in Case No. U-18238, dated May 18, 202 and consistent with the temporary waiver relating to Part III.[1]

5. UPPCO's present electric rates are based on the schedule of rates authorized by the Commission in its Order Approving Settlement Agreement dated March 24, 2023, in Case No. U-21286. That Order Approving Settlement Agreement granted rate relief of $10.8 million annually, based on a 9.9% return on common equity, effective July 1, 2023. The Commission-approved rates were based on a test year consisting of a 12-month period ending June 30, 2024.

6. UPPCO's rates for retail electric service established in Case No. U-21286 do not reflect the current costs of providing retail electric service, and UPPCO requires further rate relief. The proposed revenue increase described in this Application, as supported by the Company's testimony, exhibits, and workpapers, is necessary to allow UPPCO to continue to provide safe and

[1] UPPCO represents that pursuant to the waiver, Attachment 14 is not part of the Company's Part III filing. Although the Company's testimony, exhibits, and supporting information contain much of the information requested in Attachment 14, UPPCO is unable to produce all of the information at this time. Consequently, UPPCO requests that the temporary waiver of compliance with the new Part III filing requirements, which was granted in the Commission's May 23, 2023 Order in Case No. U-18236, be extended with respect to Attachment 14 for the duration of this case.

reliable electric service, to meet service quality and reliability expectations, and to allow UPPCO a reasonable opportunity to recover its costs of operation, including a reasonable rate of return.

REQUESTED RELIEF

7. For purposes of this case, UPPCO has undertaken a complete examination of its investments, expenses and revenues based on a projected 12-month period ending December 31, 2025. Using a 2025 calendar test year and a return on common equity of 10.7%, UPPCO calculates a base rate revenue deficiency of approximately $16.9 million. UPPCO represents that such an increase is just and reasonable under the circumstances and is necessary to provide a reasonable return on UPPCO's electric utility plant and resources required to provide service in Michigan.

8. The key drivers contributing to the Company's revenue deficiency are:

(a) the necessity of continuing investment in reliability infrastructure,

(b) increasing costs of capital, including debt and equity, and

(c) rising operational expenses for equipment and personnel needed to provide electric service.

9. UPPCO represents that its present return on investment is and will be below that required by sound regulation; that UPPCO's present retail electric rates and charges are unjust and unreasonable because they will produce increasingly inadequate retail electric service revenues to UPPCO, unless rate relief is granted to permit UPPCO to continue to achieve its goal of rendering adequate retail electric service to the public. UPPCO further represents that rate relief, effective in the near future, is necessary to protect the rights of UPPCO and to prevent it from being deprived of its property contrary to the Fourteenth Amendment of the Constitution of the United States of America and contrary to the provisions of the Constitution of 1963 of the State of Michigan.

10. UPPCO represents that in order to establish rates for retail electric service that are just and reasonable, it is essential that the Commission order an increase in retail electric base rates that will produce additional revenues on an annual basis of approximately $16.9 million.

RATE DESIGN, TARIFF AND OTHER PROPOSALS

11. UPPCO's proposed rates for each customer class rate schedule are shown on Schedule F2 of Exhibit A-11. These rates are designed to recover the revenue deficiency, and also reflect an update to the Company's class cost of service study evidenced in Schedule F1 of Exhibit A-11. UPPCO requests Commission approval of the proposed rates.

12. In addition, UPPCO proposes to continue the Company's Residential Low-Income tariff. UPPCO does not propose to change the PSCR Base or loss factor.

IMPLEMENTATION OF RATES

13. UPPCO proposes to implement its revised rates no later than January 21, 2025, after the Commission issues an order approving UPPCO's request.

TESTIMONY AND EXHIBITS

14. UPPCO is filing herewith written testimonies, exhibits and work papers in support of the requested rate increase and related approvals requested herein. The positions and relief described in the direct testimony and exhibits should be considered as if specifically requested in this Application. UPPCO is also filing a proposed Protective Order to govern the release, use and disclosure of certain testimony, exhibits and responses in Part III that contain confidential information, or in future response to discovery.

15. UPPCO represents that the proposals contained in this Application, and in the supporting testimonies, exhibits and work papers are just, reasonable and in the public interest.

WHEREFORE, UPPER PENINSULA POWER COMPANY requests that this Commission:

A. Set an early hearing date on this Application for rate relief;

B. Find and determine that UPPCO's existing rates and charges for retail electric service are unreasonably low, inadequate, and should be increased;

C. Authorize UPPCO to adjust its existing retail electric service rates so as to produce a return on common equity of not less than 10.7%;

D. Authorize UPPCO to file and make effective, at the earliest possible date, but no later than January 21, 2025, its proposed increases to annual revenue, and approve other modifications to the rates, rules, and regulations as are described in the testimony and exhibits that accompany this Application; and

E. Grant UPPCO such other and further relief and authorizations as may be lawful and proper.

Respectfully submitted,

UPPER PENINSULA POWER COMPANY

Paul Collins

Digitally signed by: Paul Collins
DN: CN = Paul Collins email = collinsp@millercanfield.com C = AD O = Miller Canfield
Date: 2024.03.21 14:37:24 -04'00'

Dated: March 21, 2024

By:_____________________________________

One of Its Attorneys
Sherri A. Wellman (P38989)
Paul M. Collins (P69719)
Benjamin J. Holwerda (P82110)
MILLER, CANFIELD, PADDOCK and STONE, PLC
One Michigan Avenue, Suite 900
Lansing, MI 48933
(517) 487-2070

Attorneys for Upper Peninsula Power Company

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

NOTICE OF HEARING
FOR THE ELECTRIC CUSTOMERS OF
UPPER PENINSULA POWER COMPANY
CASE NO. U-21555

- Upper Peninsula Power Company requests Michigan Public Service Commission's approval for authority to increase its rates for the generation and distribution of electricity and other relief.

- The information below describes how a person may participate in this case.

- You may call or write Upper Peninsula Power Company, 1002 Harbor Hills Dr., Marquette, MI 49855, (800) 562-7680 for a free copy of its application. Any person may review the application at the offices of Upper Peninsula Power Company or on the Commission's website at: michigan.gov/mpscedockets.

- The prehearing conference in this matter will be held:

DATE/TIME:	**___________, _________, 2024, at _____ a.m.**
BEFORE:	Administrative Law Judge _____________
LOCATION:	**Video/Teleconferencing**
PARTICIPATION:	Any interested person may participate. Persons needing any assistance to participate should contact the Commission's Executive Secretary at (517) 284-8090, or by email at mpscdockets@michigan.gov in advance of the hearing.

The Michigan Public Service Commission (Commission) will hold a hearing to consider Upper Peninsula Power Company's (UPPCO) March 21, 2024 application for approval to increase its existing rates and charges for retail electric service. UPPCO requests Commission approval to: 1) increase the Company's jurisdictional revenue requirement by approximately $16.9 million; 2) adjust its existing retail electric service rates so as to produce a return on common equity of not less than 10.7%; 3) file and make effective no later than January 21, 2025, its proposed increases to annual revenue, and approve other modifications to the rates, rules, and regulations; and 4) all other changes and suggestions made and supported in UPPCO's testimony and exhibits.

All documents filed in this case shall be submitted electronically through the Commission's E-Dockets website at: michigan.gov/mpscedockets. Requirements and instructions for filing can be found in the User Manual on the E-Dockets help page. Documents may also be submitted, in Word or PDF format, as an attachment to an email sent to: mpscedockets@michigan.gov. If you require assistance prior to e-filing, contact Commission staff at (517) 284-8090 or by email at: mpscedockets@michigan.gov.

Any person wishing to intervene and become a party to the case shall electronically file a petition to intervene with this Commission by **____________, 2024**. (Interested persons may elect to file using the traditional paper format.) The proof of service shall indicate service upon UPPCO's attorney, Paul M. Collins, Miller, Canfield, Paddock & Stone, P.L.C., One Michigan Avenue, Suite 900, Lansing, MI 48933.

Any person wishing to participate without intervention under Mich Admin Code, R 792.10413 (Rule 413), or file a public comment, may do so by filing a written statement in this docket. The written statement may be mailed or emailed and should reference Case No. **U-21555**. Statements may be emailed to: mpscedockets@michigan.gov. Statements may be mailed to: Executive Secretary, Michigan Public Service Commission, 7109 West Saginaw Hwy., Lansing, MI 48917. All information submitted to the Commission in this matter becomes public information, thus available on the Michigan Public Service Commission's website, and subject to disclosure. Please do not include information you wish to remain private. For more information on how to participate in a case, you may contact the Commission at the above address or by telephone at (517) 284-8090.

Requests for adjournment must be made pursuant to Michigan Office of Administrative Hearings and Rules R 792.10422 and R 792.10432. Requests for further information on adjournment should be directed to (517) 284-8130.

A copy of UPPCO's request may be reviewed on the Commission's website at: michigan.gov/mpscedockets and at the office of Upper Peninsula Power Company. For more information on how to participate in a case, you may contact the Commission at the above address or by telephone at (517) 284-8090.

The Utility Consumer Representation Fund has been created for the purpose of aiding in the representation of residential utility customers in various Commission proceedings. Contact the Chairperson, Utility Consumer Participation Board, Department of Licensing and Regulatory Affairs, P.O. Box 30004, Lansing, Michigan 48909, for more information.

Jurisdiction is pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1919 PA 419, as amended, MCL 460.54 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; 1982 PA 304, as amended, MCL 460.6j et seq.; and the Michigan Administrative Hearing System's Administrative Hearing Rules, 2015 AC, R 792.10401 et seq.

__________, 2024

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **UPPER PENINSULA POWER COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21555

<u>PROTECTIVE ORDER</u>

This Protective Order governs the use and disposition of Protected Material that Upper Peninsula Power Company ("Applicant"), or any other Party discloses to another Party during the course of this proceeding. The Applicant or other Party disclosing Protected Material is referred to as the "Disclosing Party"; the recipient is the "Receiving Party" (defined further below). The intent of this Protective Order is to protect non-public, confidential information and materials so designated by the Applicant or by any other party, which information and materials contain confidential, proprietary, or commercially sensitive information. This Protective Order defines "Protected Material" and describes the manner in which Protected Material is to be identified and treated. Accordingly, it is ordered:

I. "Protected Material" and Other Definitions

A. For the purposes of this Protective Order, "Protected Material" consists of trade secrets or confidential, proprietary, or commercially sensitive information provided in Disclosing Party's materials responsive to Part III of the Commission's rate case filing requirements approved in Case No. U-18238 and testimony, exhibits, work papers, discovery or audit responses, any witness' related exhibit and testimony, and any arguments of counsel describing or relying upon the Protected Material. Subject to challenge under Paragraph IV.A, Protected Material shall consist of non-public confidential information and materials including, but not limited to, the following information disclosed during the course of this case if it is marked as required by this Protective Order:

1. Trade secrets or confidential, proprietary, or commercially sensitive information provided in response to discovery, in response to an order issued by the presiding hearing officer or the Michigan Public Service Commission ("MPSC" or the "Commission"), in testimony or exhibits filed later in this case, or in arguments of counsel;

2. To the extent permitted, information obtained under license from a third-party licensor, to which the Disclosing Party or witnesses engaged by the Disclosing Party is a licensee, that is subject to any confidentiality or non-transferability clause. This information includes reports; analyses; models (including related inputs and outputs); trade secrets; and confidential, proprietary, or commercially sensitive information that the Disclosing Party or one of its witnesses receives as a licensee and is authorized by the third- party licensor to disclose consistent with the terms and conditions of this Protective Order;

3. Information that could identify the bidders and bids, including the winning bid, in a competitive solicitation for a power purchase agreement or in a competitively bid engineering, procurement, or construction contract at any stage of the selection process *(i.e.,* before the Disclosing Party has entered into a power purchase agreement or selected a contractor); and

4. Information that is protected as confidential in other jurisdictions that Applicant provides utility service.

B. The information subject to this Protective Order does not include:

1. Information that is or has become available to the public through no fault of the Receiving Party or Reviewing Representative and no breach of this Protective Order, or information that is otherwise lawfully known by the Receiving Party without any obligation to hold it in confidence;

2. Information received from a third party free to disclose the information without restriction;

3. Information that is approved for release by written authorization of the Disclosing Party, but only to the extent of the authorization;

4. Information that is required by law or regulation to be disclosed, but only to the extent of the required disclosure; or

5. Information that is disclosed in response to a valid, non-appealable order of a court of competent jurisdiction or governmental body, but only to the extent the order requires.

C. "Party" refers to the Applicant, MPSC Staff ("Staff'), or any other person, company, organization, or association that is granted intervention in Case No. U-21555 under the Commission's Rules of Practice and Procedure, Mich Admin Code, R 792.10401 et al.

D. "Receiving Party" means any Party to this proceeding who requests or receives access to Protected Material, subject to the requirement that each Reviewing Representative sign a Nondisclosure Certificate attached to this Protective Order as Attachment 1.

E. "Reviewing Representative" means a person who has signed a Nondisclosure Certificate and who is:

1. An attorney who has entered an appearance in this proceeding for a Receiving Party;

2. An attorney, paralegal, or other employee associated, for the purpose of this case, with an attorney described in Paragraph I.E.1;

3. An expert or employee of an expert retained by a Receiving Party to advise, prepare for, or testify in this proceeding; or

4. An employee or other representative of a Receiving Party with significant responsibility in this case.

A Reviewing Representative is responsible for assuring that persons under his or her supervision and control comply with this Protective Order.

F. “Nondisclosure Certificate” means the certificate attached to this Protective Order as Attachment 1, which is signed by a Reviewing Representative who has been granted access to Protected Material and agreed to be bound by the terms of this Protective Order.

II. Access to and Use of Protected Material

A. This Protective Order governs the use of all Protected Material that is marked as required by Paragraph III.A and made available for review by the Disclosing Party to any Receiving Party or Reviewing Representative. This Protective Order protects: (i) the Protected Material; (ii) any copy or reproduction of the Protected Material made by any person; and (iii) any memorandum, handwritten notes, or any other form of information that copies, contains, or discloses Protected Material. All Protected Material in the possession of a Receiving Party shall be maintained in a secure place. Access to Protected Material shall be limited to persons authorized to have access subject to the provisions of this Protective Order.

B. Protected Material shall be used and disclosed by the Receiving Party solely in accordance with the terms and conditions of this Protective Order. A Receiving Party may authorize access to, and use of, Protected Material by a Reviewing Representative identified by the Receiving Party, subject to Paragraphs III and V below, only as necessary to analyze the Protected Material; make or respond to discovery; present evidence; prepare testimony, argument, briefs, or other filings; prepare for cross-examination; consider strategy; and evaluate settlement. These individuals shall not release or disclose the content of Protected Material to any other person or use the information for any other purpose.

C. The Disclosing Party retains the right to object to any designated Reviewing Representative if the Disclosing Party has reason to believe that there is an unacceptable risk of misuse of confidential information. If a Disclosing Party objects to a Reviewing Representative, the Disclosing Party and the Receiving Party will attempt to reach an agreement to accommodate that Receiving Party's request to review Protected Material. If no agreement is reached, then either the Disclosing Party or the Receiving Party may submit the dispute to the presiding hearing officer. If the Disclosing Party notifies a Receiving Party of an objection to a Reviewing Representative, then the Protected Material shall not be provided to that Reviewing Representative until the objection is resolved by agreement or by the presiding hearing officer.

D. Before reviewing any Protected Material, including copies, reproductions, and copies of notes of Protected Material, a Receiving Party and Reviewing Representative shall sign a copy of the Nondisclosure Certificate (Attachment 1 to this Protective Order) agreeing to be bound by the terms of this Protective Order. The Reviewing Representative shall also provide a copy of the executed Nondisclosure Certificate to the Disclosing Party.

E. Even if no longer engaged in this proceeding, every person who has signed a Nondisclosure Certificate continues to be bound by the provisions of this Protective Order. The obligations under this Protective Order are not extinguished or nullified by entry of a final order in this case and are enforceable by the MPSC or a court of competent jurisdiction. To the extent Protected Material is not returned to a Disclosing Party, it remains subject to this Protective Order.

F. Members of the Commission, Commission staff assigned to assist the Commission with its deliberations, and the presiding hearing officer and his or her staff shall have access to all Protected Material that is submitted to the Commission under seal without the need to sign the Nondisclosure Certificate.

G. A Party retains the right to seek further restrictions on the dissemination of Protected Material to persons who have or may subsequently seek to intervene in this MPSC proceeding.

H. Nothing in this Protective Order precludes a Party from asserting a timely evidentiary objection to the proposed admission of Protected Material into the evidentiary record for this case.

III. Procedures

A. The Disclosing Party shall mark any information that it considers confidential as "CONFIDENTIAL: SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-21555." If the Receiving Party or a Reviewing Representative makes copies of any Protected Material, they shall conspicuously mark the copies as Protected Material. Notes of Protected Material shall also be conspicuously marked as Protected Material by the person making the notes.

B. If a Receiving Party wants to quote, refer to, or otherwise use Protected Material in pleadings, pre-filed testimony, exhibits, cross-examination, briefs, oral argument, comments, or in some other form in this proceeding (including administrative or judicial appeals), the Receiving Party shall do so consistent with procedures that will maintain the confidentiality of the Protected Material. For purposes of this Protective Order, the following procedures apply:

1. Written submissions using Protected Material shall be filed in a sealed record to be maintained by the MPSC's Docket Section, or by a court of competent jurisdiction, in envelopes clearly marked on the outside, "CONFIDENTIAL —SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-21555. Simultaneously, identical documents and materials, with the Protected Material redacted, shall be filed and disclosed the same way that evidence or briefs are usually filed;

2. Oral testimony, examination of witnesses, or argument about Protected Material shall be conducted on a separate record to be maintained by the MPSC's Docket Section or by a court of competent jurisdiction. These separate record proceedings shall be closed to all persons except those furnishing the Protected Material and persons otherwise subject to this Protective Order. The Receiving Party presenting the Protected Material during the course of the proceeding shall give the presiding officer or court sufficient notice to allow the presiding officer or court an opportunity to take measures to protect the confidentiality of the Protected Material; and

3. Copies of the documents filed with the MPSC or a court of competent jurisdiction, which contain Protected Material, including the portions of the exhibits, transcripts, or briefs that refer to Protected Material, must be sealed and maintained in the MPSC's or court's files with a copy of the Protective Order attached.

C. It is intended that the Protected Material subject to this Protective Order should be shielded from disclosure by a Receiving Party. If any person files a request under the Freedom of Information Act with a governmental agency participating in this proceeding, including, but not limited to, the MPSC, the MPSC Staff, and the Michigan Attorney General, seeking access to documents subject to this Protective Order, the governmental agency shall promptly notify the Disclosing Party, and the Disclosing Party may take whatever legal actions it deems appropriate to protect the Protected Material from disclosure. In light of Section 5 of the Freedom of Information Act, MCL 15.235, the notice must be given at least five (5) business days before the governmental agency grants the request in full or in part.

IV. Termination of Protected Status

A. A Receiving Party reserves the right to challenge whether a document or information is Protected Material and whether this information can be withheld under this Protective Order. In response to a motion, the Commission or the presiding hearing officer in this case may revoke a document's protected status after notice and hearing. If the presiding hearing officer revokes a document's protected status, then the document loses its protected status after

14 days unless a Party files an application for leave to appeal the ruling to the Commission within that time period. Any Party opposing the application for leave to appeal shall file an answer with the Commission no more than 14 days after the filing and service of the appeal. If an application is filed, then the information will continue to be protected from disclosure until either the time for appeal of the Commission's final order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired.

B. If a document's protected status is challenged under Paragraph IV.A, the Receiving Party challenging the protected status of the document shall explicitly state its reason for challenging the confidential designation. The Disclosing Party bears the burden of proving that the document should continue to be protected from disclosure.

V. Retention of Documents

Protected Material remains the property of the Disclosing Party. The Protected Material only remains available to the Receiving Party, unless the Receiving Party is an agency/public official of the State of Michigan subject to state documentation retention schedules, until the time expires for petitions for rehearing of a final MPSC order in this Case No. U-21555 or until the MPSC has ruled on all petitions for rehearing in this case (if any). Should the Receiving Party be an agency/public official of the State of Michigan who retains the Protected Material to comply with applicable state documentation retention schedules, it is acknowledged that this Order will continue in effect and said Receiving Party will be required to retain the Protected Material in accordance with this Order. Furthermore, it is understood that an attorney for a Receiving Party who has signed a Nondisclosure Certificate and who is representing the Receiving Party in an appeal from an MPSC final order in this case may retain copies of Protected Material until either the time for appeal of the Commission's final order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired. On or before the time specified by the preceding sentences, the Receiving Party shall return to the Disclosing Party all Protected Material in its possession or in the possession of its Reviewing Representatives-including all copies and notes of Protected Material-or destroy the Protected Material and, at the request of the Disclosing Party, certify in writing that is has done so.

Notwithstanding the preceding paragraph, counsel for a Receiving Party may maintain in a single confidential file of Protected Material beyond the resolution of this proceeding, provided that this Order will continue in effect with respect to the Protected Material for so long as it is retained by counsel for any requesting Party. If the Protected Material is relevant or reasonably calculated to lead to admissible evidence in another Commission proceeding relating to and involving the Disclosing Party, then it may be used subject to the issuing of a new protective order in that case. The terms of this Paragraph shall apply until the later of (i) the resolution of Applicant's next general electric rate case conducted after the conclusion of Case No. U-21555, or (ii) the resolution of any and all Power Supply Cost Recovery ("PSCR") plan or PSCR reconciliation cases that may be filed before the resolution of the next general electric rate case. For purposes of this paragraph, the "resolution" of a case means the expiration of the period of judicial review fo a final order of the Commission. Counsel for the requesting Party or Parties shall have the right to retain copies of the pleadings, orders, transcripts, briefs, comments, and exhibits in these proceedings, but this protective order will continue in effect with respect to the Protected Material contained in these documents.

VI. Limitations and Disclosures

The provisions of this Protective Order do not apply to a particular document, or portion of a document, described in Paragraph II.A if a Receiving Party can demonstrate that it has been previously disclosed by the Disclosing Party on a non-confidential basis or meets the criteria set forth in Paragraphs I.B.1 through I.B.S. A Receiving Party intending to disclose information taken directly from materials identified as Protected Material must-before actually disclosing the information-do one of the following: (i) contact the Disclosing Party's counsel of record and obtain written permission to disclose the information, or (ii) challenge the confidential nature of the Protected Material and obtain a ruling under Paragraph IV that the information is not confidential and may be disclosed in or on the public record.

VII. Remedies

If a Receiving Party violates this Protective Order by improperly disclosing or using Protected Material, the Receiving Party shall take all necessary steps to remedy the improper disclosure or use. This includes promptly notifying the MPSC, the presiding hearing officer, and the Disclosing Party, in writing, of the identity of the person known or reasonably suspected to have obtained the Protected Material. A Party or person that violates this Protective Order remains subject to this paragraph regardless of whether the Disclosing Party could have discovered the violation earlier than it was discovered. This paragraph applies to both inadvertent and intentional violations. Nothing in this Protective Order limits the Disclosing Party's rights and remedies, at law or in equity, against a Party or person using Protected Material in a manner not authorized by this Protective Order, including the right to obtain injunctive relief in a court of competent jurisdiction to prevent violations of this Protective Order.

ORDERED BY:

____

, Administrative Law Judge

Attachment 1

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
UPPER PENINSULA POWER COMPANY	)	
for authority to increase its rates for	)	Case No. U-21555
the generation and distribution of	)	
electricity and for other relief.	)	
____	)	

NONDISCLOSURE CERTIFICATE

By signing this Nondisclosure Certificate, I acknowledge that access to Protected Material is provided to me under the terms and restrictions of the Protective Order issued in Case No. U-21555, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by the terms of the Protective Order. I understand that the substance of the Protected Material (as defined in the Protective Order), any notes from Protected Material, or any other form of information that copies or discloses Protected Material, shall be maintained as confidential and shall not be disclosed to anyone other than in accordance with the Protective Order.

Reviewing Representative

Date: __________, 2024

____

Title:
Representing:

____

Printed Name

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application of **UPPER PENINSULA POWER COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief	))))	Case No. U-21555

CERTIFICATION OF FILING REQUIREMENTS

Eric W. Stocking, Director of Regulatory & Power Supply for Upper Peninsula Power Company, states that, other than Attachment 14 of the new Part III filing requirements, which is subject to the temporary waiver and specifically identified in the Application, he has provided the data required pursuant to the Rate Case Filing Requirements established by the Commission's order dated May 18, 2023, issued in Case No. U-18238, and pursuant to these requirements, certifies the data so provided.

Dated: March 21, 2024

Eric W. Stocking

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
***

In the matter of the application of	)	
UPPER PENINSULA POWER COMPANY	)	
for authority to increase its rates for the generation	)	Case No. U-21555
and distribution of electricity and other relief.	)	
	)	

DIRECT TESTIMONY AND EXHIBITS OF

ERIC W. STOCKING

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

March 21, 2024

QUALIFICATIONS

Q. Please state your name and business address for the record.

A. My name is Eric W. Stocking. My business address is 1002 Harbor Hills Drive, Marquette, Michigan 49855.

Q. By whom are you employed and in what capacity?

A. I am employed by Upper Peninsula Power Company ("UPPCO" or the "Company"), as the Director of Regulatory Affairs & Power Supply.

Q. Briefly describe your educational background and applicable professional experience.

A. I graduated from Michigan State University in 2009 with a Bachelor of Science in Economics. In February 2010, I entered into employment with the Michigan Public Service Commission ("MPSC" or the "Commission") Staff as an economic analyst in the Generation and Certificate of Need section with responsibilities related to generation resource adequacy, load forecasting, integrated resource planning, capacity expansion modeling, and utility capital investment related to compliance with Federal and State air quality regulations. In the fall of 2016, I accepted the role of Economic Specialist in the Resource Adequacy and Retail Choice section of the MPSC Staff, where I played an active role in the implementation of several aspects of PA 341 and 342 of 2016, including the provisions related to the State Reliability Mechanism and Integrated Resource Planning. In November of 2017, I left my employment with the MPSC Staff and began working at UPPCO as a Rate Analyst within the Regulatory Affairs department, and provided testimony in UPPCO's 2018 rate case, 2019 Integrated Resource Plan ("IRP") proceeding, among others. In November 2019, I assumed the role of Manager of Rates and Power

Supply with the Company. In this role, my primary responsibilities included power supply and resource planning, managing regulatory affairs efforts, and leading cost of service and rate design issues. In April 2023, I assumed my current role with the Company, where I am responsible for leading all regulatory affairs, power supply, energy waste reduction, and beneficial electrification efforts for UPPCO.

Q. Have you previously testified before the Commission?

A. Yes. I have provided testimony in several cases before the Commission. Recent notable examples include the following proceedings on behalf of UPPCO: Case No. U-21286 (General Rate Case), Case No. U-20350 (Integrated Resource Plan) ("IRP"), Case No. U-21513 (Depreciation Rates), and PSCR plan and reconciliation cases, most recently, Case Nos. U-20810 and U-20811.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. Initially, I will provide a general case overview and introduce the Company witnesses that will be providing direct testimony in this proceeding. Following this overview, I will provide supporting testimony in the following areas:

1. General Case Overview
2. Forecast Methodology
3. Projected Test Year Revenue Deficiency
4. Projected Test Year Cost of Service Study ("COSS")
5. State Reliability Mechanism ("SRM"): Capacity Charge
6. Projected Test Year Power Supply Costs ("PSCR")

7. Projected Test Year Operations & Maintenance Costs
8. Projected Test Year Capital Expenditures ("CAPEX") Summary
9. U-21513 Depreciation Case

Q. Are you sponsoring any exhibits, which were prepared by me or under my direction?

A. Yes, I am sponsoring the following exhibits in conjunction with my direct testimony.

- Exhibit A-6, Schedule A1 (EWS-1): Projected Revenue Deficiency
- Exhibit A-7, Schedule B5 (EWS-2): Projected CAPEX Summary
- Exhibit A-11, Schedule F1 (EWS-3): Projected Cost of Service Allocation Study
- Exhibit A-17 (EWS-4): UPPCO CAPEX Detail by Business Line
- Exhibit A-32 (EWS-5): State Reliability Mechanism Capacity Charge
- Exhibit A-33 (EWS-6): Present & Equalized Revenue / Unit Cost Summary
- Exhibit A-34 (EWS-7): Production Demand Component
- Exhibit A-35 (EWS-8): State Reliability Mechanism 3(b) Offset Calculation
- Exhibit A-36 (EWS-9): U-21513 Depreciation Case Summary Result

I am also referencing the following the following Exhibits that are sponsored by Company witnesses Wonch, Ringler, Schlorke, Gervae, Brynick, and Kates.

- Exhibit A-3 (NLW-11), Schedule C5: Historical Operation and Maintenance Expenses
- Exhibit A-8 (NLW-27), Schedule C5: Projected Operation and Maintenance Expenses
- Exhibit A-7 (VES-1), Schedule B5.1: Projected Power Generation CAPEX

- Exhibit A-7 (JRR/DJG-1), Schedule B5.4: Projected Distribution & Substation CAPEX
- Exhibit A-7 (JJB-1), Schedule B5.5: Projected AMI CAPEX
- Exhibit A-7 (JJB-2), Schedule B5.6: Projected Total Corporate | General CAPEX
- Exhibit A-18 (JJB-3): UPPCO Facility CAPEX Detail
- Exhibit A-19 (DJG-2): UPPCO Substation CAPEX Detail
- Exhibit A-20 (VES-2): UPPCO Generation CAPEX Detail
- Exhibit A-21 (JRR-3): UPPCO Distribution CAPEX Detail
- Exhibit A-22 (NEK-14): UPPCO Information Technology CAPEX Detail

Q. Please identify other witnesses presenting direct testimony in support of the Company's filing and the topic that each witness will be addressing.

A. The following witnesses will be providing direct testimony on behalf of UPPCO in this proceeding:

- **Natasha L. Wonch** presents testimony in support of the Company's proposed revenue requirement calculations, including revenue, operating expenses, taxes, and the calculation of rate base.
- **Nicholas E. Kates** presents testimony in support of the Company's proposed capital structure, forecast adjustments, and pension and OPEB related expenses, and Information Technology related CAPEX.
- **John S. Thompson, Ph.D.** presents testimony in support of the Company's requested Return on Equity ("ROE") and common equity ratio.
- **Jay R. Ringler** presents testimony in support of the Company's proposed CAPEX for Distribution, including strategic underground conversion of overhead conductors, distribution reliability metrics, and the Company's vegetation management program.

- **Daniel J. Gervae** presents testimony in support of the Company's proposed CAPEX for Substation projects.
- **Virgil E. Schlorke** presents testimony in support of the Company's proposed CAPEX for power generation projects.
- **Jason J. Brynick** provides testimony in support of the Company's proposed CAPEX projects related to fleet, facility, and Advanced Metering Infrastructure ("AMI").
- **Kay L. Ryan** presents testimony in support of the Company's employee benefits and other human resources related matters.
- **Nicole E. Bell** presents testimony in support of the projected test year sales forecast, proposed rate design, residential income assistance ("RIA") tariff offering, distributed generation ("DG") program, and proposed tariffs.

GENERAL CASE OVERVIEW

Q. What is UPPCO's historical test year in this proceeding?

A. UPPCO has used a historical test year ending December 31, 2023.

Q. What is UPPCO's projected test year in this proceeding?

A. UPPCO has used a projected test year ending December 31, 2025.

Q. How does the Company present the historical and projected test year revenue deficiencies?

A. The Company presents the historical and projected revenue deficiency calculations in compliance with the Commission's Standard Filing Requirements that were approved in Case No. U-18238.

Q. Please provide a brief description of UPPCO and its service territory.

A. UPPCO is the largest utility in Michigan's Upper Peninsula serving approximately 53,000 customers across 10 of the 15 counties. UPPCO was founded in 1947 through a merger of several smaller entities, serving a predominantly rural service territory that spans over 4,460 square miles. The Company owns 7 hydroelectric facilities and one gas-fired turbine generator, with a total nameplate capacity of approximately 57 MW.

Q. Please briefly describe the most recent UPPCO Commission-approved general rate relief.

A. On March 24, 2023, the Commission issued an order approving a settlement agreement in Case No. U-21286 that resulted in a $10.8 million annual increase in electric rates, implementation of a Residential Income Assistance ("RIA") tariff provision, and an increase to the discretionary Distributed Generation ("DG") cap from 3% to 4.5%, among other items. The net revenue increase from the settlement agreement was 11.2% overall and 10.9% for the residential customer class, with rates taking effect on July 1, 2023.

Q. In general terms, why has the Company initiated this rate proceeding?

A. The primary drivers of this rate proceeding are UPPCO's continued infrastructure investments and associated operating expenditures necessary to continue to improve the reliability and resiliency of UPPCO's distribution system, and general inflation and supply chain pressures that continue to impact the United States economy, putting upward pressure on the Company's operational expenses. The Company is seeking rate relief in this proceeding such that it can continue to effectively manage deployment of both capital and operations resources that are required to ensure the Company's ability to continue to provide exceptionally safe, reliable, and efficient delivery of electric services to our customers.

Additionally, in Case No. U-21286, UPPCO agreed that it would not, pursuant to MCL 460.6a, request an adjustment to its base rates to take effect prior to January 1, 2025. UPPCO's request in the instant proceeding is consistent with this direction provided in the Commission's order approving Case No. U-21286.

As discussed above, as UPPCO continues to invest in infrastructure necessary to improve the reliability and resilience of its systems, as well as adapt itself to the increased pricing levels observed throughout the U.S. economy over the last several years. The testimony and exhibits presented in this case demonstrate that UPPCO's existing rates will not be sufficient to cover the Company's cost of providing service during the projected test year, including a reasonable return. Approval of the rates proposed in this case is reasonable and necessary to allow UPPCO to timely recover costs and earn a reasonable return, while meeting the Company's customers' needs for reliable service.

Q. Please summarize the impact of key drivers on the revenue requirement presented in this case.

A. The Company requests jurisdictional rate relief in the amount of $16.9 million, which is summarized as shown in Table 1:

Table 1 (in millions)

Key Drivers of Revenue Requirement		Total
Investment	$	4.6
Cost of Capital	$	0.4
Operating Expenses (excluding O&M)	$	5.6
O&M Expenses	$	6.4
Sales / Revenue	$	1.5
Jurisdictional Rate Relief	**$**	**18.5**
Previously Ordered Revenue Credits	$	(1.6)
Total Revenue Requirement Impact	**$**	**16.9**

Q. Please provide a summary of the key drivers as depicted in Table 1.

A. Table 1 provides a financial bridge from the outcome of UPPCO's most recent electric rate increase outcome, Case No. U-21286, to the Company's requested jurisdictional rate relief in the instant proceeding, inclusive of revenue offset impacts, based on a projected test year ending December 31, 2025, reflecting the individual impact of investment, cost of capital, operations and maintenance ("O&M") expenses, the impact of sales and revenue, and top-line revenue adjustments that were approved by prior Commission order.

Based upon the evidentiary support provided in this application, UPPCO requests that the Commission authorize the Company to adjust its retail electric generation and distribution rates so as to result in a total revenue increase of $16.9 million annually.

FORECAST METHODOLOGY

Q. Please describe the general approach utilized by the Company in supporting its projected test year positions and recommendations in this case.

A. UPPCO utilized actual historical data as the point of departure for most estimated costs for the projected test period. These historical costs were then adjusted for the impact of inflation. Certain other costs reflect specific estimates or projections where general impacts of inflation alone would not be adequate to represent a true projection of cost. Costs not adjusted solely by the assumed inflation factor are addressed specifically in the testimony of Company witness Kates or evidenced in the Exhibit A-12 (NEK-11).

Q. Please describe the major components of UPPCO's forecast that informed the projected test year ending December 31, 2025.

A. The major components are as follows:

1. Sales and demand forecast. Based on historical data, UPPCO utilized a combination of econometric forecasting and historical trends to derive its sales and demand forecasts by specific rate categories (i.e., residential, commercial, industrial, lighting, etc.). Company witness Bell is providing direct testimony supporting UPPCO's sales and demand forecasts for the projected test year. A summary of historical and forecasted sales volumes is included in Schedules E1 through E1.3 of Exhibit A-5 (NEB-1 through NEB-3) and Schedules E1.1 through E2.2 of A-10 (NEB-4 through NEB-8).
2. Power supply cost. For purposes of establishing jurisdictional revenue requirements, UPPCO has utilized a power supply cost forecast that is equal to the Company's approved PSCR Base cost, inclusive of the approved loss factor. Said differently, for the purposes of this proceeding, the power supply cost forecast is assumed to be equal to the costs that would be experienced if the average PSCR cost equaled $45.57 per

MWh. Fuel and purchased power costs are represented at Schedule C4 of Exhibit A-8 (NLW-26).

3. Operating revenue forecast. Based upon the sales and demand forecasts previously discussed, UPPCO applies the approved retail and wholesale rates to derive its present revenue forecast. UPPCO's projected test year operating revenues are evidenced at line 2 of Schedule C1 of Exhibit A-8 (NLW-23), whereby present rates are applied to the projected test year sales and demand figures.

4. Operating expenditures forecast. First, operating expenditure forecasts, excluding power supply costs, are derived through a combination of cost center budgets as well as historical expenditures and trends. The primary cost centers that comprise UPPCO's O&M forecasts are production, distribution, customer accounts, customer service, and administrative and general expenses. For these costs, UPPCO used the 2023 historical test year costs as the basis for the projected test year. Then, UPPCO escalated these 2023 actual values by an inflation factor to derive the projected test year values, and subsequently made certain forecast adjustments to the projected test year based upon other budgetary and/or known and measurable information. A summary of these forecast adjustments is identified as Exhibit A-12 (NEK-11), forecast adjustment summary. A summary of projected operating expenses is detailed by Schedule C1 of Exhibit A-8, (NL2-23).

5. Capital expenditures forecast. The capital expenditures forecast is developed by the Company's finance department, along with UPPCO's engineering and planning departments, and reflects expenditures and in-service dates of major projects during the year, as well as the amounts approved to fund routine capital blanket project

work. Supporting testimony for the projected test year CAPEX forecast for distribution, substation, power generation, fleet, facilities, information technology, and AMI is provided by Company witnesses Ringler, Gervae, Schlorke, Brynick, and Kates. Specifically, a summary of total CAPEX for the projected test year are evidenced by Schedule B5 of Exhibit A-7 (EWS-2).

6. Capital Structure. In determining the Company's capital structure, UPPCO establishes how it plans to fund its overall operations and growth. Consideration is given to interest coverage and other regulatory restrictions, timing of capital requirements, availability of equity capital, and corporate objectives such as credit metrics, planned large capital projects, and short-term debt limitations. Support for the Company's proposed capital structure through the end of the projected test year is provided in the testimony of Company witness Kates, and a summary of the proposed capital structure is included as Schedule D1 of Exhibit A-9 (NEK-6).

PROJECTED TEST YEAR REVENUE DEFICIENCY

Q. Please explain the revenue deficiency depicted on Schedule A1 of Exhibit A-6 (EWS-1).

A. Schedule A1 of Exhibit A-6 (EWS-1) calculates UPPCO's projected test year revenue deficiency for the projected test period ending December 31, 2025, based upon its projected rate base, adjusted net operating income, and overall rate of return. Once the net income deficiency has been established, a revenue conversion factor is applied to gross up this value for taxes, and ultimately present this value as a revenue deficiency.

Finally, proper accounting for of revenue offsets established and approved for recovery in prior Commission Orders are applied to revenue requirement, which increases the revenue deficiency. The final revenue deficiency is then added to forecasted present revenue to establish total revenue requirement, allowing the Company to achieve its required rate of return.

Line 24 of Exhibit A-6, Schedule A1, reflects UPPCO's total revenue deficiency of $18.162 million annually, and UPPCO's retail revenue deficiency of $16.914 million annually for the projected test year. These revenue deficiencies represent a percentage increase of 15.6% and 45.5% compared to present <u>total</u> revenue, respectively.

Q. Please describe the revenue offset and adjustments listed, beginning on line 18 and continuing through line 22, of Schedule A1 of Exhibit A-6 (EWS-1).

A. UPPCO has included the following revenue adjustments at this location, all of which were approved by prior Commission action:

1. <u>U-20995 Revenue Offset</u>: As established in the final Commission order approving settlement in Case No. U-20995, this revenue offset addresses the amortization and recovery of the regulatory asset established by settlement point 2(h), whereby the Commission directed the following: (1) extended the expiration of certain "revenue credits" that were in base rates from May 1, 2022 through June 30, 2022, (2) authorized the formation of a regulatory asset that would accrue at $393,000 per month (i.e., the value of certain expiring "revenue credits") until rates are authorized by a final Commission order in UPPCO's next general rate case or July 1, 2023, whichever occurs first, and (3) further authorized that UPPCO in its next general rate

case can recover in rates over a two-year amortization period, the value of this regulatory asset including application of the carrying costs equivalent to UPPCO's weighted average cost of capital. As shown in line 18 of Schedule A1 of Exhibit A-6, this revenue offset is valued at $1,241,192, which reflects the remaining six months of unamortized revenue offset that was approved for inclusion in rates in Case No. U-21286. UPPCO proposes to amortize this amount of the 12-month projected test period ending December 31, 2025.

2. U-20757 Revenue Adjustment: As established in the Commission order issued on April 15, 2020 ("April 15 Order") in Case No. U-20757, the Commission outlined steps that it had taken to respond to COVID-19 and directed additional actions to protect the public and ensure continuity of energy and telecommunications services under the Commission's jurisdiction. Among those additional actions the Commission "authorize[d] all electric, natural gas, and steam utilities under its jurisdiction to defer uncollectible, or bad debt, expense incurred beginning March 24, 2020, that are in excess of the amount used to set current rates."[1] Further, the Commission's March 24, 2023 order ("March 24 Order") approving settlement stated that "The parties further agree that UPPCO may establish a regulatory asset in the amount of $863,118 (related to the amount recorded in Case No. U-20757), but this amount will be reduced by $200,000 which will be donated to organizations benefitting low-income customers (after consultation with the Staff and the Attorney General). The remaining balance of $663,118 will be amortized over two years

[1] See April 15 Order, p. 15.

ending no later than June 30, 2025."[2] Therefore, at line 20 of Schedule A1 of Exhibit A-6, UPPCO has included the amount of $165,779, which reflects the remaining six months of unamortized revenue offset that was approved for inclusion in rates in Case No. U-21286. UPPCO proposes to amortize this amount of the 12-month projected test period ending December 31, 2025.

3. U-20276 Revenue Adjustment: As established in Case No. U-20276, settlement point 9(i) directed UPPCO to utilize a pension expense of $1.019 million and "…record any future pension expense below that amount, on a yearly basis, as a regulatory liability…" to be refunded at a later data as approved by the Commission in a future rate proceeding. As such, at line 22 of Schedule A1 of Exhibit A-6, the Company calculates a value of ($421,484) which represents a 12-month period of the full regulatory liability being amortized over a three-year period.

PROJECTED TEST YEAR COST OF SERVICE STUDY

Q. What is the purpose of your direct testimony relating to the Cost of Service study?

A. The purpose of my direct testimony on this topic is to discuss and support the class Cost of Service Study ("COSS") that is being utilized to design rates for the projected test year.

[2] See March 24 Order, p. 2.

Company Witness Bell's direct testimony related to rate design relies on the results of the COSS for the projected test year to develop UPPCO's proposed changes to rate design in both year one and two of the Company's proposed rate implementation period.

Q. What exhibit and schedules support UPPCO's COSS study?

A. As demonstrated in Schedule F1 of Exhibit A-11 (EWS-3), UPPCO provides its projected test year COSS with the following sub-schedules:

1. Sch SUM – Summary of Operating Income & Rate Base (present and proposed)
2. Sch PLT – Electric Plant in Service
3. Sch D&A – Reserve for Depreciation and Amortization
4. Sch RBO – Additions & Deduction to Rate Base
5. Sch REV – Operating Revenues
6. Sch O&M – Operation & Maintenance Expense
7. Sch DAX – Depreciation & Amortization Expense
8. Sch OTX – Taxes Other Than Income Taxes
9. Sch ITX – Development of Income Taxes
10. Sch S&W – Development of Salaries & Wages Allocation Factor
11. Sch AF – Allocation Factors
12. Sch AP – Allocation Proportions
13. Sch ADA – Allocated Direct Assignments
14. Sch RRW – Total Revenue Requirements (Workpaper)

These schedules constitute the fundamentals of the COSS that is prepared for the retail electric jurisdiction, along with the associated allocation methodologies, supplemental analyses, and data.

Q. What is the purpose of a class cost of service study?

A. A class cost of service study is conducted in order to determine the revenue requirement for each class of customers, and consequently design rates to recover the amounts prescribed by the COSS. This task is accomplished by assigning, or allocating, the detailed components of UPPCO's revenue requirement to individual classes using allocation factors that reflect the nature of the particular cost component being allocated. In allocating the detailed total company cost components to classes, UPPCO's total cost of service is distributed among the various customer classes in such a manner that the sum of the class revenue requirements equals the company's total revenue requirement. This type of COSS is generally referred to as a "fully distributed" cost of service study, since all company costs that make up the revenue requirement are allocated to classes.

Q. Please generally describe the guiding principles relied upon by UPPCO in performing the projected test year COSS.

A. In general, a sound COSS approach should provide an outcome whereby the rates that a certain customer group pays should be designed to recover the costs that those same certain customers caused the utility to incur. Cost causation is the central principle which is pertinent to all cost of service studies for allocating costs across customer classes.

Q. Why are costs allocated to customer classes?

A. Costs are allocated to customer classes in order to provide customer class revenue guidelines for rate design purposes. In addition, the cost study results provide information regarding the level of classified component costs per unit (i.e., demand cost per kW or kWh, energy costs per kWh, and customer costs per customer per month) which may be useful in the design of rates. The use of cost of service studies as a guide to rate design is a standard practice among utilities.

Q. Please generally describe the steps involved in conducting a class cost of service study.

A. There are three primary steps involved in performing a class cost of service study: (1) functionalization, (2) classification, and (3) allocation. Functionalization identifies the operational source where the costs are incurred, either directly or indirectly, with respect to the physical process of providing service. For example, the costs of generating units and purchased power (production function) are identified separately from costs associated with transmission lines (transmission function) which are, in turn, segregated from the costs of the distribution system (distribution function).

The second step in conducting a cost of service study, classification, refers to the separation of costs according to the usage characteristic that drives the cost – i.e., demand, energy, and customer-related costs. Demand costs are costs that arise as a result of the rate of power consumption over a short period of time (usually 15 minutes to an hour). Energy costs are those costs that result from the volume of energy supplied over time. Customer costs are costs that vary as a function of the number of customers.

The third and final step in conducting a cost of service study is allocation. Allocation is the process of using customer class metrics, along with the knowledge that certain costs are incurred exclusively for the benefit of specific identifiable customers (direct assignments), to allocate the specific cost components that have been functionalized and classified to individual customer classes. Customer class information such as non-coincident peak demands, coincident peak demands, annual energy use, and customer counts are utilized to inform rate class allocation factors.

Q. Please describe how the Company's projected test year COSS performs the process of cost functionalization.

A. After all the individual cost components representing the total revenue requirement have been identified, the components are then separated according to the function or physical service they provide. The FERC Uniform System of Accounts ("USOA") definitions are used as a guide to assign these items to their various functions. These functions are:

1. Production – costs associated with the production of energy and capacity, including purchased power;
2. Transmission – costs associated with the high voltage system that transports the power to load sinks;
3. Distribution – costs associated with distributing the energy from the transmission system to the retail customers;
4. Customer Service – costs associated with providing service to the customer –i.e., service drops, metering, billing, the customer-related portion of transformers and conductors, and similar costs; and

5. Administrative and General – common costs, such as management, buildings, software, support services, and similar indirect costs that are incurred to support the other functions of electric service.

Q. Please describe how the Company's projected test year COSS performs the process of cost classification.

A. Cost classification is the process of further categorizing the functionalized costs, established in step one, according to the cost driving characteristic of the type of utility service that is provided. The three primary cost classifications are demand-related costs, energy-related costs, and customer-related costs.

Demand-related costs are those fixed costs that are related to the kilowatt ("kW") demand that the customers place on the system at any point in time. These costs vary with the maximum demand imposed on the various facilities of the power system by customers. Energy-related costs are costs that are related to the kilowatt-hours ("kWh") of energy that the customer utilizes over time. These costs, such as fuel and purchased energy expenses, vary with the overall quantity of energy provided to retail customers. Customer-related costs are those costs incurred as a result of the number of customers on the system. These costs, such as meters, billing, and distribution service laterals, are incurred for the sole purpose of serving individual customers.

Q. Following functionalization and classification of the various components that make up total cost of service, what is the next step in the process of calculating class costs of service?

A. After functionalization and classification, class responsibility for each cost is determined using the allocation factors referred to above. Each identifiable element of the total UPPCO revenue requirement is allocated to each customer class on the basis of the demands imposed by the class (using either coincident peak ("CP") demands or non-coincident peak ("NCP") demands), energy use by class at the generation source (i.e., after accounting for line and transformation losses), or number of customers served (weighted by the appropriate weighting factor to recognize differences in types of customers and their impacts upon the system). These allocations are then summarized within the cost of service model to derive costs of service for each customer class.

Q. Please describe the layout and operation of the projected test year COSS model you are sponsoring in this proceeding.

A. The class cost of service model I am sponsoring as Schedule F1 of Exhibit A-11, Projected Test Year COSS, is organized as a cost matrix. Each row of the model identifies a particular detailed component of the total UPPCO cost to provide service. The columns of the study consist of the allocations of cost to each customer class. The development of the cost of serving each customer class begins with the allocation of rate base, revenues, and continues with the allocation of operating expenses, taxes, and the calculation of labor and other allocators.

Q. Please describe the output and sub-schedules of Schedule F1 of Exhibit A-11 (EWS-3).

A. The sub-Schedules are identified on the left-most column of the COSS output. Line 43 at Pages 1 through 4 of sub-Schedule SUM in the class cost of service study summarize the allocated components of revenue requirement and present the rates of return by customer class at present rates. As indicated by this summary, the present rates charged to certain customer classes produce a rate of return for that class that is below the system average rate of return, while the present rates charged to other customer classes produce a higher than system average rate of return. The rates of return at present rates are also shown as ratios of the class return to the system return, which are referred to in the COSS as the "Index Rate of Return". An Index Rate of Return of 1.00 means that the class return is the same as the system return. An Index Rate of Return of less than 1.00 means that the class return is less than the system return. Conversely, an Index Rate of Return of greater than 1.00 means that the class return is greater than the system return.

Pages 5 through 8 of sub-Schedule SUM of the class cost of service study summarize the allocated components of revenue requirement and present the rates of return by customer class at UPPCO's authorized rate of return of 6.94%. The results summarized on this page set forth the revenue requirements by customer class that are required for each class to pay its respective costs of service.

Pages 9 through 20 of the class cost of service study summarize the allocation of rate base to classes. The allocations of gross plant in service are provided on pages 9 through 20 as represented in sub-Schedule PLT. The allocations of reserve for depreciation are provided on pages 21 through 24 as represented in sub-Schedule D&A. Additions and deductions to rate base are provided on pages 25 through 28 along with the summary of rate base by class of service as represented in sub-Schedule RBO at line 32.

As represented in sub-Schedule REV, allocated class Operating Revenues are provided on pages 29 through 32. The allocation of operation and maintenance expense by account is set forth on pages 33 through 52 as represented in sub-Schedule O&M. Pages 53 through 56 provide the detailed allocation of depreciation expense by account to customer classes as represented in sub-Schedule DAX. Taxes Other than Income Taxes are allocated to classes on pages 57 through 60 as represented in sub-Schedule OTX. The components of Income Taxes and the calculation of Income Taxes by customer class are provided on pages 61 through 76 as represented in sub-Schedule ITX. Of note, Income Taxes are not directly allocated to customer classes, but rather the components used to calculate income taxes are allocated to classes instead. These allocated income tax components are then used to calculate the Income Tax liability independently for each class based upon the class's allocated tax components.

The remaining pages of the class cost of service study provide the information used to develop the allocation factors employed in the cost study. Pages 77 through 88 detail the development of the salaries and wages allocation factors used in the cost of service study as represented in sub-Schedule S&W. Pages 89 through 148 provide the detailed information used to develop the other allocation factors employed in the class cost of service study. These allocation factors consist of both externally and internally developed allocation factors. Externally developed allocation ratios reflect customer class metrics such as coincident peak and non-coincident peak demands at various voltage levels, energy sales and as measured at both the generation level and at the meter (i.e., with and without line and transformation losses), and number of customers by voltage level. Externally developed allocation factors are developed outside of the cost of service model and then input into it. In contrast, internally developed allocation factors are calculated within the cost of service model using previously allocated cost components to derive factors that reflect the combined impacts of multiple cost drivers. Finally, pages 145 through 148 provide a summary of total revenue requirements at present and claimed rate of return.

Q. Please explain the relevance of Exhibit A-33 (EWS-6) – Present Equalized Revenue and Unit Cost Summary.

A. Exhibit A-33 (EWS-6) provides an alternative view of the projected test year COSS results. Specifically, it provides unit cost information, at present and claimed rate of return, for each cost component that makes up the rate class and total company revenue requirement. Generally speaking, this information is meant to provide fundamental guidance to the rate design process. As discussed by Company Witness Bell, UPPCO is proposing to increase the fixed customer charge across several rate categories, based upon the bifurcation of customer-related cost components and the resulting rates defined by Exhibit A-33 (EWS-6).

Q. Has the Commission provided direction on the types of costs that should be included in the calculation of a service charge?

A. Yes. In its January 18, 1974, Order in Case No. U-4331, the Commission stated that:

> *"The maximum allowable service charge would be limited to those costs associated directly with supplying service to the customer. Only costs associated with metering, the service lateral, and customer billing are includable since these are the costs that are directly incurred as the result of a customer's connection to the gas system."*

Q. Does the Commission language quoted in the previous question also apply to electric utilities?

A. Yes. The same philosophy applies to electric utilities.

Q. Has the Commission upheld similar principles in recent cases?

A. Yes. The Commission has spoken to these principles consistently since the issuance of the Order quoted above.

Q. Please describe the items included in the calculation of required service charges, as outlined at Line 38 of pages 13 through 16 of Exhibit A-33 (EWS-6).

A. As shown at lines 37 through 47 of pages 13 through 16 of Exhibit A-33 (EWS-6), the costs components included in the calculation of the proposed customer charges include values for the following cost types:

- Distribution Service Laterals
- Metering Component
- Meter Reading Component
- Customer Account, Sales, & Service Component.
- Customer Other
- Street and Area Lighting Component[3]

Q. Are the cost components included in the derivation of the proposed customer charge cost component, on a dollar per month per customer basis, consistent with the Commission directive in U-4331?

Q. Not entirely. This method of deriving customer charge notably excludes any portion of general plant, and administrative & general expenses in the calculation of an appropriate

[3] Street and Area Lighting Component contains values only for UPPCO's lighting rate schedules. No value is incorporated for other rate categories.

customer charge. The National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual classifies a portion of general plant and A&G expenses as customer-related costs. This type of allocation rests on the theory, as presented in this manual, that general plant supports all functions (including Customer). Therefore, a portion of general plant should be included in the customer charge calculation, and any calculation of a customer charge which excludes these costs would be incorrect. Additionally, the NARUC Electric Utility Cost Allocation Manual recommends that A&G expenses should be allocated using a labor or plant allocation basis, both of which would result in some portion of A&G expenses being included as a customer-related cost. As a result, any method to calculate an appropriate customer charge that does not consider general plant or administrative and general costs in the derivation of such a charge is incomplete and misaligned with standard cost allocation practices.

Q. Are there other reasons that the Company proposes to increase the customer related charge for residential and small commercial customers?

A. Yes. UPPCO's service territory is largely rural and sparsely populated, covering an immense amount of land that is used by many for recreational purposes. As a result, a significant portion of the residential accounts that UPPCO provides service to are seasonal in nature, with only intermittent usage registered at the premises throughout a given year. Therefore, when examining UPPCO's residential class usage, customers, and revenue in aggregate, it appears that an average residential customer of UPPCO uses significantly less energy on a monthly and annual basis when compared to other utilities within the State. However, this data requires careful interpretation, as the aggregate view of residential use per customer is diluted by the high proportion of seasonal premises within the population.

In this situation, a fixed charge that is inadequate leads to a situation whereby full-time residents are subsidizing the total revenue requirement attributable to the residential customer class, as the customers with intermittent and/or zero usage for a given month are not contributing to the total fixed cost of providing service to the residential class. This leads to the average rate paid by a full-time, typical usage residential customer being higher than it otherwise would be, ceteris paribus.

The Company's proposal to increase the fixed charge applied to residential and small commercial customer classes, which exhibit a higher proportion of seasonal usage type customers, will result in a mitigation of the previously described subsidization, whereby seasonal customers will contribute their fair share toward the fixed costs of providing service to all applicable customers, even with intermittent or zero usage during a given month.

Q. Are other similarly situated and adjacent utilities applying a higher fixed charge to these customer classes?

A. Yes. For example, Alger Delta Cooperative Electric Association ("Alger Delta") applies a monthly service charge of $45.00 per month[4] to residential customers. Alger Delta provides service to a primarily rural service territory, which is comparable to UPPCO.

[4] Alger Delta Cooperative Electric Association Tariff Book, Sheet D-4.00. https://www.algerdelta.com/sites/algerdelta.com/files/RATE%20BOOK%2003JUL23.pdf

Cloverland Electric Cooperative ("Cloverland") applies a monthly service charge of $24.00 per month[5] to residential customers. Cloverland provides service to a primarily rural service territory, which is comparable to UPPCO.

Ontonagon County Rural Electrification Association ("Ontonagon REA") applies a monthly service charge of $20.00 per month[6] to residential customers. Ontonagon REA provides service to a primarily rural service territory, which is also comparable to UPPCO.

Marquette Board of Light and Power ("Marquette BLP") applies a monthly service charge of $24.00 per month[7] to residential customers outside the Marquette city limits (Rate R1/R2). Marquette BLP provides service to a primarily urban service territory, which is significantly less rural than UPPCO's service territory.

The City of Negaunee applies a monthly service charge of $25.00 per month[8] to residential customers within the Negaunee city limits. Negaunee provides service to a

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[5] Cloverland Electric Cooperative Tariff book, Schedule RES1.
https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/electric/cloverland-and-cloverland-ES/cloverland5cur.pdf?rev=4a10704db1d84cecb4cff1a7c33041aa&hash=5D4A9C01AF2E1B6BA2CF9A8E708D88CE

[6] Ontonagon County Rural Electrification Association Tariff Book, Sheet D-4.00.
https://ontonagon.coop/docs/Rates_Regulations.pdf

[7] Marquette Board of Light and Power website.
https://mblp.org/other-customer-information/#ratescc97-5136

[8] City of Negaunee website.
https://www.cityofnegaunee.com/treasurer-utility-billing

primarily urban service territory, which is significantly less rural that UPPCO's service territory.

Q. Is the Company's proposal relating to the proposed fixed charge to be applied residential and small commercial customer billings in alignment with these comparable utilities that are electrically adjacent to UPPCO?

A. Yes it is. Although the Company's proposal is a step in the right direction, this proposal results in a lower fixed charge than the adjacent utilities discussed previously. Company witness Bell outlines the Company's proposed rate design in this proceeding.

Q. In your opinion, what factors account for the difference between UPPCO's current customer charges when compared to this group of similarly situated electric utilities?

A. I was not involved in the derivation of rates for this group of similarly situated utilities, but it appears that this group of utilities designed their rates to meet targeted objectives that are unique to the Upper Peninsula of Michigan, inclusive of the vast, rural areas that we all serve.

Q. Is the COSS the Company has presented in this filing transparent and verifiable?

A. Yes. The class cost of service study submitted as Schedule F1 of Exhibit A-11 (EWS-3) provides complete detail as to each allocation made on an account-by-account basis. In addition, cross-references to supporting schedules are provided on all summary pages. Every calculation made in the model can be readily verified by the Staff and any intervening parties. Although the cost of service model UPPCO has employed in this filing is subject to protective restrictions because its internal computations are confidential trade secrets, UPPCO will provide a working model of its licensed cost of service study to the Staff and intervenors upon execution of the necessary confidentiality agreements.

Q. Do all tabs within the Company's COS include traditional Microsoft Excel formulas?

A. No. The COS model "COST OF SERVICE" tab, is the only tab that utilizes traditional Microsoft Excel formulas to functionalize, classify, and allocate costs. The "FUNCTIONS" and "UNBUNDLED" tabs contain summaries from the 20 cost component files generated from the COS model. To generate these files, the COS model menu item options "Add-Ins COS, Functions/Components, Create Functions/Components Schedules" need to be selected. This will create 20 cost component files and also update the FUNCTIONS and the UNBUNDLED sheets in the COS model with the numbers found in these cost component files. Once generated, the numbers found in these 20 cost components can be compared to the numbers found in the FUNCTIONS and UNBUNDLED sheets of the COS Model. The "FUNCTIONS" tab of the COS model summarizes the numbers found in the INTEGRATED RETAIL SYSTEM column (Excel column E) for each of the 20 cost component files. These numbers will appear as values since they are copied in as values from these cost component files. The "UNBUNDLED" tab of the COS model copies the " Sch RRW - Total Revenue Requirements (Workpaper)" page for each of the 20 cost components. These numbers will appear as values since they are copied in as values from the 20 component files. These 20 cost components are then summarized by rate class and cost component at Present and Equalized rates of returns at the bottom of this tab.

Q. What are the major sources of the cost data analyzed in UPPCO's COSS?

A. All cost of service data has been extracted from UPPCO's projected test year revenue requirements exhibits along with any associated workpapers. Where more detailed information was required to perform various supplementary analyses related to certain plant and expense elements, the data was either taken directly from UPPCO's various software systems or derived from the historical books and records of UPPCO.

Q. Please describe how you defined the customer classes in UPPCO's projected test year COSS.

A. The customer classes that were allocated costs in the projected test year COSS follow the rate schedules under which UPPCO currently provides retail service in Michigan.

The customer classes shown in the UPPCO COSS consist of the following:

1. A-1: Residential Service in the Integrated System;
2. A-2: Residential Service in the Iron River District (CLOSED);
3. AH-1: Residential Heating Service;
4. C-1: General Service in the Integrated System;
5. H-1: Commercial Heating Service;
6. P-1: Light and Power Service;
7. CP-U: Large Commercial and Industrial Service;
8. RTMP: Real-Time Market Pricing;

9. WP-3: Light and Power Service, (served at transmission or sub-transmission voltages) with a billing demand greater than 5,000 kW and a minimum of 500 kW of on-site generation;

10. SL-3: Street Lighting for customer owned street lighting and/or traffic signal systems;

11. SL-5: Street Lighting for municipality-owned street lighting systems;

12. SL-6: Street Lighting for UPPCO-owned street lighting systems;

13. Z-3: Dusk to Dawn Outdoor Security Lighting in the Integrated System; and

14. Z-4: Dusk to Dawn Outdoor Security Lighting in the Iron River District (CLOSED).

Q. Are the customer classes defined in the same manner in UPPCO's projected test year COSS as they were in UPPCO's Commission-approved 2023-24 COSS in Case No. U-21286?

A. Yes. The Company is not proposing to consolidate or otherwise change the structure of its rate schedules in this proceeding.

Q. Does the COSS allocate costs to the rate classes as defined in present rates?

A. The COSS submitted for the projected test year in this proceeding is based upon rates that are currently in effect, or present rates. All values in the COSS are allocated to each rate class utilizing the allocator's defined name found in the column titled "Allocation Basis".

Q. Regarding the classification of FERC account 364 through 368, does the projected test year COSS classify these accounts in the same manner compared to the COSS approved in UPPCO's last rate case, Case No. U-21286?

A. Yes, it does.

Q. Please describe UPPCO's approach in the development of its COSS.

A. As stated earlier when describing the general procedures for preparing a COSS, UPPCO's COSS attempts to associate costs with customer classes based on cost causation principles. In some instances, there can be a direct association of costs to customers based on causation. For example, some plant costs such as investment in meters and services can be directly associated with the number of customers. In other cases, causation can be based on a direct relationship between costs and some parameter that can be related to customers. An example of this is fuel cost, which has a direct relationship to customers' energy usage; therefore, fuel costs are allocated to customers based on energy usage. Other costs may have relationships to customer parameters that are not direct but are significantly influenced by those parameters. Distribution system costs fall into this category.

Q. How does UPPCO allocate the costs of Power Supply Resources to the rate classes?

A. In this filing, the allocation of power supply resources employs the use of a 12CP 75% & Energy 25% method in accordance with the MPSC's order in Case No. U-4771. The Demand classified production allocation factor is weighted on the basis of 75% of the 12 months of coincident peak ("12-CP") Demand of firm system load, and 25% Energy. The use of a 75% demand, 25% energy ratio allocation of power supply costs is the same method that was proposed by UPPCO and approved by the Commission in Case U-20276.

In determining the cost causal factors associated with generation resources, it is useful to recognize that an electric utility's power supply resources are generally composed of a mix of peaking and base load generation. In such a power supply mix, a portion of an electric utility's power supply resources often reflect the use of high capital costs generation investment coupled with low fuel costs (i.e., base load generation) to meet a level of continuous base load throughout most hours of the year. In instances in which an electric utility employs capital intensive generation with the expectation of operating at a fairly high continuous rate of use through all hours of the year, a trade-off between high capital costs and low fuel costs tends to be the most economically efficient manner to meet annual system load requirements. In contrast, peaks of short duration may be met most efficiently by the use of peaking units which typically have lower capital costs than base load generation, but higher fuel costs. Thus, a mix of peaking and base load generation is employed to meet the total load of a utility throughout the year.

There are a number of allocation methods that analyze the operating and dispatch characteristics of individual supply resources, and that separately allocate these individual supply resources on the basis of when the resources are utilized and what the customer class loads are at specific times. These allocation methods require extensive operating data as well as extensive class load data by hour. In addition, these allocation methods are often the subject of intense debate since a number of underlying assumptions may be disputed by various parties. The 12CP 75% & Energy 25% method considers peak demand impacts (which affects the total capacity requirements of the power supply system) as well as average demand (i.e., energy) impacts (which affects the extent to which the utility is willing to invest in higher capital cost base load generation).

Therefore, the 12CP 75% & Energy 25% allocation method recognizes those factors that give rise to the power supply demand costs being allocated.

Q. How does UPPCO allocate transmission costs to customers?

A. In the case of transmission costs, UPPCO employs the use of a 12CP allocation method. Transmission plant must be built to meet the maximum demands placed upon it. The maximum loadings that occur on UPPCO's transmission system each month are the most appropriate metric to employ in allocating transmission costs, as they are analogous to how UPPCO is billed for network transmission service on a monthly basis by American Transmission Company ("ATC").

It is important to note that, unlike generation resources, decisions to build transmission plant do not entail tradeoffs between capital costs and energy costs. The same type and size transmission line would be built to meet a given maximum load regardless of whether the line is expected to be lightly loaded or heavily loaded at other times. Thus, an allocation method such as 12CP 75% & Energy 25% method, which has an average demand (i.e., energy) component, is not appropriate for allocating transmission costs. To reflect the costs incurred and to allocate accordingly, the 12CP allocator is used at the rate class level.

Q. How does UPPCO allocate distribution costs to customers?

A. In the case of distribution costs, UPPCO relies upon two significant cost causation principles. Some distribution costs are incurred in order for customers to simply be connected to the distribution system. Other distribution costs are incurred due to the level of demand of customers.

Q. How does UPPCO allocate electric production costs and investment to each rate schedule?

A. UPPCO first classifies production costs and investment within the appropriate categories of Energy or Demand. The Energy classified production costs are allocated based on the kWh energy usage by rate schedule. In accordance with the MPSC's order in Case No. U-4771, UPPCO has allocated the Demand classified production costs and investment using the Demand – Production allocator, which is weighted on the basis of 75% of the 12-CP Demand of firm system load, and 25% Energy.

Q. How does UPPCO allocate transmission costs to each rate schedule?

A. UPPCO classifies transmission costs and investment to Demand, and then transmission costs and investment are allocated to the rate schedules using the Transmission allocator, which is based upon the 12-CP demands of total system load (i.e., both firm and interruptible).

Q. Are Transmission O&M expenses allocated in the same manner as other Transmission costs and plant investment?

A. Transmission O&M expense is allocated similarly in the sense that the Transmission O&M allocator is based upon the 12-CP demands of total system load (i.e., both firm and interruptible).

Q. How does UPPCO allocate customer costs to each rate schedule?

A. In general, customer costs are allocated based on total annual customer counts by rate schedule.

Q. Please summarize the results of UPPCO's projected test year COSS.

A. The results of the COSS with respect to the revenue deficiency at present rates by rate schedule and based upon the requested revenue requirement for UPPCO's retail jurisdiction are summarized in sub-Schedule RRW of Schedule F1 of Exhibit A-11 (EWS-3).

Q. In your opinion, does the COSS for the projected test year provide a reasonable basis for establishing rates in this case?

A. Yes, it does. The COSS for the projected test year is a reasonable estimate of revenue requirements by rate schedule, given the total revenue requirement, and supports the rates requested in this case, as explained further in the direct testimony of Company Witness Bell.

STATE RELIABILITY MECHANISM CAPACITY CHARGE

Q. Please explain UPPCO's considerations related to establishing a State Reliability Mechanism ("SRM") capacity charge in this proceeding.

A. Pursuant to Section 6w of Public Act 341 of 2016 ("PA 341"), an electric utility must establish a SRM capacity charge that meets the following criteria:

Section 6w (3)(a) states that:

> *"For the applicable term of the capacity charge, include the capacity related generation costs included in the utility's base rates, surcharges, and power supply cost recovery factors, regardless of whether those costs result from utility ownership of the capacity resources or the purchase or lease of the capacity resource from a third party."*

Section 6w (3)(b) states that:

"For the applicable term of the capacity charge, subtract all non-capacity-related electric generation costs, including, but not limited to, costs previously set for recovery through net stranded cost recovery and securitization and the projected revenues, net of projected fuel costs, from all of the following:

(i) All energy market sales.

(ii) Off-system energy sales

(iii) Ancillary services sales.

(iv) Energy sales under unit-specific bilateral contracts."

Furthermore, the Commission's November 4, 2021, Order in Case No. U-21104 clarified that the next review of UPPCO's SRM capacity charge will occur in the Company's next general rate case (i.e., the instant case). Additionally, this Commission Order clarified that "all energy market sales" as defined by Section 6w(3)(b)(i) above should consist of "Company generation and purchases pursuant to contract" and should be calculated as the hourly locational marginal price ("LMP") times the energy in question. As discussed later in my testimony, UPPCO relies upon this clarification to apply the non-capacity related offsets required by Section 6w(3)(b) ("3(b) Offset").

Q. Please describe the resources relied upon by UPPCO to derive the "total capacity related generation costs included in the utility's base rates" as required by the statute.

A. UPPCO relied upon the Production Demand Component file of its projected test year COSS study, sponsored here as Exhibit A-34 (EWS-7) – Production Demand Component.

Q. Please provide additional details related to Exhibit A-34 (EWS-7) – Production Demand Component.

A. Exhibit A-34 is a subset of the total projected test year COSS presented in the instant case as Exhibit A-11, Schedule F-1. Exhibit A-34 applies the same form and calculation as the COSS, but only incorporates cost items that are functionalized as production demand related cost components, or said simply, costs that are associated with the production of capacity, namely UPPCO's owned generation assets.

Q. Please describe how UPPCO derived the "total capacity related generation costs included in the utility's base rates" as required by the statute.

A. UPPCO relied upon the information contained in Exhibit A-34 to derive the various components of "Capacity Related Revenue Requirement" that has been previously included in the prior calculation of UPPCO's capacity charge, specifically the MPSC Staff's calculation in Case No. U-18254. The components that comprise the calculation of Capacity Related Revenue Requirement are as follows, and separately listed on Exhibit A-32 (EWS-5) – State Reliability Mechanism Capacity Charge:

- Plant In Service (Production Demand Component)
- Depreciation Reserve (Production Demand Component)
- Construction Work in Progress (Production Demand Component)
- Materials & Supplies (Production Demand Component)
- Property, Payroll, & Income Tax (Production Demand Component)
- O&M Non Fuel (Production Demand Component)
- Depreciation Expense (Production Demand Component)

- Amortizations (Production Demand Component)
- Real Estate and Property Tax (Production Demand Component)
- Total Rate Base (Total Company, all cost components).

To derive the total generation cost as required by Section 6w(3)(a), UPPCO mimicked the formula used to derive the same figure in Case No. U-18254, and Case No. U-21286. Step one includes identifying the applicable net rate base amount, calculated as the sum of Plant in Service, Depreciation Reserve, Construction Work in Progress, Materials and Supplies, and Property, Payroll, and Income tax production demand components defined above multiplied by the instant case required rate of return.

Step two takes the result of step one, and adds O&M non-fuel, Depreciation Expense, and Amortization production demand components as defined above.

Step three is to apportion the amount of Real Estate and Property Tax production demand components as defined above by the ratio of production demand related net rate base to the total rate base (including all cost components) and add the resulting value to the results of step 2.

The resulting Capacity Related Revenue Requirement is described at line 12 of Exhibit A-32 (EWS-5), totaling $11.22 million for UPPCO's Total Integrated Retail System.

Q. Please describe how UPPCO calculated the required offsets to the Capacity Related Revenue Requirement, as required by Section 6w(3)(b).

A. The required 3(b) offsets require the Company to consider four factors: energy market sales, off-system energy sales, ancillary services revenue, and energy sales under unit-specific bilateral sales. I will address each of these items separately.

Q. Please describe the Company's calculation of energy market sales that are appropriate to be netted from the total Capacity Related Revenue Requirement discussed above.

A. Exhibit A-35 (EWS-8) – SRM 3(b) Offset Calculation provides a summary of the market value associated with each of UPPCO's generation units, defined as hourly production multiplied by the hourly LMP at the UPPC.Integrated pricing node. In total, the market value of UPPCO's generation anticipated for the projected test year totals $6.02 million. The Company allocated the market value of UPPCO's generation to customer classes by utilizing the firm 12CP allocator, as replicated at line 40 of Exhibit A-32 (EWS-5).

Q. Does UPPCO include the cost of its Purchased Power Agreements ("PPAs") in the formation of total Capacity Related Revenue Requirement?

A. No. UPPCO's current PPAs are firm, energy only contracts. UPPCO does not pay for capacity attributes through the term or conditions of these PPA's, nor does it acquire any capacity attributes as a result. Therefore, it is inappropriate to include the cost of these PPAs in the formation of capacity related revenue requirement, and it is consequently inappropriate to subtract any value associated with them pursuant to the 3(b) offset requirements.

Q. Please describe the Company's calculation of off-System energy sales that are appropriate to be netted from the total Capacity Related Revenue Requirement discussed above.

A. UPPCO does not have any off-system energy sales.

Q. Please describe the Company's calculation of ancillary service revenues that are appropriate to be netted from the total Capacity Related Revenue Requirement discussed above.

A. Ancillary service revenue is depicted at page 29 of Exhibit A-11, Schedule F1, the projected test year COSS at line 18, Schedule REV. UPPCO applied the same allocation of ancillary services revenue to customer classes that exists within the COSS to the formation of the SRM Capacity Charge in Exhibit A-32 (EWS-5), as shown by line 27.

Q. Please describe the total SRM capacity charge as calculated by Exhibit A-32 (EWS-5).

A. Exhibit A-32 (i) calculates the total Capacity Related Revenue Requirement at line 23, (ii) reflects the necessary 3(b) offsets at lines 25 through 29, and (iii) calculates the net Capacity Related Revenue Requirement at line 31. At line 34 of Exhibit A-32, the Net Capacity Related Revenue Requirement is divided by UPPCO's 2024/25 Summer Planning Reserve Margin Requirement ("PRMR") as submitted to the Midcontinent Independent System Operators ("MISO") Module E process. This calculation results in a SRM Capacity Charge of $50,687 / MW-Year, or $138.87 / MW-Day.

Q. Should the costs and revenue associated with providing service to UPPCO's Real Time Market Pricing ("RTMP") customer be included in the derivation of the SRM Capacity Charge?

A. No. The RTMP customer takes service from UPPCO as a customer directly interconnected with ATC, with energy rates equal to the applicable real time LMP, and transmission rates equal to the transmission costs that the Company is billed from the

ATC and MISO. As such, and understanding that Commission precedent has long held that RTMP power supply costs are segregated from full requirements customer costs that are included in PSCR calculations, there is no basis to assign a SRM capacity charge, based upon the embedded cost of UPPCO generation, to the RTMP class rates.

Furthermore, the generation service to the RTMP customer is non-firm, and subject to interruptions by UPPCO, the MISO, the ATC, or other regulating authorities. Therefore, the RTMP customer load can be characterized as fully interruptible. As a result, UPPCO does not incur any incremental purchased capacity related costs through the process of serving the RTMP customer.

Q. Please explain how the SRM Capacity Charges for each rate class calculated at line 31 of Exhibit A-32 (EWS-5) are incorporated into the rate design schedules sponsored by Company Witness Bell.

A. As described in further detail by Company Witness Bell, the total power supply revenue requirement reflected in Exhibit A-11, Schedule F3 (NEB-10) is apportioned to two categories, Capacity Related and not-Capacity related. The Capacity related revenue requirement is defined by the values included in Exhibit A-32, and the non-Capacity related value is defined as the difference between the total power supply revenue requirement established by the projected test year COSS and the rate class capacity related revenue requirement.

Q. Does the Company's proposal regarding the SRM capacity charge comport with Section 6w of PA 341 of 2016, and with prior Commission directive and precedent related to the calculation of this value.

A. Yes, the Company's proposal is consistent with guidance provided by both the statute and the Commission. Further, paragraph 9(k) of the settlement agreement resolving all issues in Case No. U-21286, which was approved by Commission order on March 24, 2023, stated that "UPPCO will adopt the State Reliability Mechanism ("SRM") capacity charge calculation method supported in the Direct Testimony and Exhibits of Eric Stocking."[9]

Q. Is your proposed method for calculating the SRM capacity charge in this proceeding consistent with the method that you proposed in your direct testimony and exhibits in Case No. U-21286?

A. Yes, it is.

PROJECTED TEST YEAR POWER SUPPLY COST

Q. Please explain the power supply costs employed by UPPCO in forecasting the projected test year.

A. UPPCO has utilized power supply costs for the projected test year that are equal to the costs derived by multiplying its PSCR related sales volumes by its previously approved PSCR Base amount of $42.90, plus its previously approved loss factor of 1.0623. Grossing up the PSCR Base by the loss amount yields an average cost projection of $45.57 per MWh.

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[9] U-21286 Settlement Agreement, p. 4.

Q. Has UPPCO proposed a new PSCR Base Rate or PSCR Loss Factor in this proceeding?

A. No. UPPCO will carry forward the PSCR Base Rate and PSCR Loss Factor that were established in Case No. U-20276. Accordingly, the PSCR Base Rate proposed by UPPCO in this proceeding will remain at 42.90 mills per kWh at the generation level, or 45.57 mills per kWh at the sales level after accounting for a loss factor of 1.0623.

Q. What will the PSCR Factor be when UPPCO's new rates go into effect?

A. The maximum authorized PSCR Factor will be established in UPPCO's 2025 PSCR Plan.

Q. Why did UPPCO choose to carry forward the PSCR Base Rate and PSCR Loss Factor?

A. Power supply costs are planned and reconciled annually in PSCR proceedings. Given the current market volatility, it is better to consider all issues arising from power supply costs in these annual proceedings rather than to try to predict energy market conditions nearly two years in the future.

Q. Has the Company included any revenue relating to PSCR <u>factor</u> in the calculation of its present revenue, as shown on Schedule A1 of Exhibit A-6 (EWS-1)?

A. No. Since power supply costs were derived by assuming that power supply costs would be equal to the existing PSCR Base (inclusive of losses), any consideration of PSCR factor revenue in the derivation of present revenue would create a mismatch of PSCR related costs and revenue. UPPCO maintains that PSCR related costs (either in excess of or less than the PSCR Base amount, inclusive of losses) cannot influence total revenue requirement in a general rate proceeding. UPPCO's method ensures that PSCR related costs and revenues remain in balance in the Company's presentment of this case.

PROJECTED TEST YEAR OPERATIONS & MAINTENANCE COSTS

Q. Please describe the current level of O&M expenses experienced by the Company.

A. As described by Exhibit A-3 (NLW-11), Schedule C5, during calendar year 2023 the Company incurred O&M expenses totaling $37.230 million, with $36.758 million of the total being attributable to providing service to the Company's jurisdictional retail customers. Exhibit A-3 (NLW-11), Schedule C5 also provides a summary of total actual O&M expenses by business line, including production, distribution, transmission, customer accounts, customer service, sales, and administrative & general ("A&G").

Q. Please describe the level of O&M expenses anticipated to be incurred by the Company during the projected test period.

A. As described by Exhibit A-8 (NLW-27), Schedule C5, during the projected test period ending December 31, 2025, the Company expects to incur O&M expenses totaling $41.361 million, with $40.823 million of the total being attributable to providing service to the Company's jurisdictional retail customers. Similar to the prior discussion, Exhibit A-8 (NLW-27) provides a summary of total actual O&M expenses by business line.

Q. Explain how the projected O&M expenses included in Exhibit A-8 (NLW-27), Schedule C5, were derived.

A. Consistent with the discussion provided in the Forecast Methodology section of my direct testimony, UPPCO utilized actual historical data (in this case, 2023) as the point of departure for most estimated costs for the projected test period. These historical costs were then adjusted for the impact of inflation during the bridge period and the projected test year. Certain other costs items reflect specific estimates or projections where general impacts of inflation alone would not be adequate to represent a true projection of cost.

Q. Please describe the composition of production-related O&M, as reflected on Exhibit A-8 (NLW-27), Schedule C5, and identify any notable change in any category from the historical test period to the projected test period.

A. Production related O&M expenses include costs relating to steam power production, hydraulic power generation, other power generation, and system control and load dispatching.

<u>Steam power production (FERC 511)</u>: Steam power generation expenses totaled $15,527 during calendar year 2023 and are anticipated to total $16,294 in 2025. The increase is primarily attributable to general inflation.

<u>Hydraulic power generation (FERC 535-545)</u>: Hydraulic power generation expenses totaled $2,995,151 during calendar year 2023 and are anticipated to total $2,888,111 in 2025, a decrease of 2.3%.

<u>Other power generation (FERC 546-554)</u>: Other power generation expenses totaled $21,874 during calendar year 2023 and are anticipated to total $59,771 in 2025. This increase is primarily due to required maintenance activities at other power generation plant.

<u>System control and load dispatching (FERC 556)</u>: System control and load dispatching expenses totaled $1,704,694 during calendar year 2023 after reclassification of Schedule 24 related expenses to FERC 564.4. During 2025, system control and load dispatching expenses are anticipated to total $2,180,951. Net of the historical period adjustment to FERC 556, the overall change would display a decrease, overall.

In summary, UPPCO's projection of production related O&M expenses for the projected test period ending December 31, 2025, inclusive of historical period adjustments to FERC 556, is anticipated to be 9.5% greater than 2023 actual values.

Q. Please describe the composition of distribution-related O&M, as reflected on Exhibit A-8 (NLW-27), Schedule C5, and identify any notable change in any category from the historical test period to the projected test period.

A. Distribution related O&M expenses include costs included in FERC accounts 580-598. Notable changes that increase the projection of distribution related O&M expenses for the projected test year include labor ($629 thousand), vehicles ($554 thousand), and American Transmission Company ("ATC") related expenses ($340 thousand).

Even with these changes, UPPCO's projection of distribution related O&M expenses for the projected test period ending December 31, 2025, is anticipated to be 2.1% greater than 2023 actual values, an increase less than the rate of general inflation anticipated for the same period.

Q. Please describe the composition of customer accounts-related O&M, as reflected on Exhibit A-8 (NLW-27), Schedule C5, and identify any notable change in any category from the historical test period to the projected test period.

A. Customer accounts related O&M expenses include costs included in FERC accounts 901-905. There are no notable changes to any category, excluding the calculation of bad debt sponsored by Company witness Kates, and the total increase in customer accounts related O&M expenses for the projected test period ending December 31, 2025, is anticipated to be 1.5% greater than 2023 actual values, an increase less than the rate of general inflation anticipated for the same period.

Q. Please describe the composition of customer service-related O&M, as reflected on Exhibit A-8 (NLW-27), Schedule C5, and identify any notable change in any category from the historical test period to the projected test period.

A. Customer service related O&M expenses include costs included in FERC accounts 907-909. Notable changes within this category include vacant positions during 2023 that are anticipated to be filled by 2025, thereby leading to an increase in total customer service expense.

In summary, UPPCO's projection of customer service related O&M expenses for the projected test period ending December 31, 2025, is anticipated to be 30% greater than 2023 actual values.

Q. Please describe the composition of A&G-related O&M, as reflected on Exhibit A-8 (NLW-27), Schedule C5, and identify any notable change in any category from the historical test period to the projected test period.

A. A&G related O&M expenses include costs included in FERC accounts 920-935. Notable changes within this category include labor ($283 thousand), and benefits including required pension contribution and OPEB ($2.823 million) as discussed in the direct testimony of Company witness Kates.

In summary, UPPCO's projection of A&G related O&M expenses for the projected test period ending December 31, 2025, is anticipated to be 26.3% greater than 2023 actual values.

Q. What is your opinion regarding the actual and projected O&M expenses shown in Exhibit A-3 (NLW-11), Schedule C5, and Exhibit A-8 (NLW-27), Schedule C5, respectively.

A. The actual expenses for calendar year 2023 were incurred in a reasonable and prudent manner, and the projected expenses for calendar year 2025 were derived based upon a holistic analysis of past expenses and projected requirements for labor and materials necessary for the Company to continue to provide safe, reliable, and efficient distribution of electric power, as well as expectations for maintaining and improving customer service.

PROJECTED TEST YEAR CAPEX SUMMARY

Q. Please describe Schedule B5 of Exhibit A-7 (EWS-2).

A. Exhibit A-7 (EWS-2), Schedule B5, provides a summary of capital spending as supported by various Company witnesses. This exhibit provides capital spending for the bridge year and projected test year. Actual spending during the previously rate case test year in Case No. U-21286 is not provided, as the relevant time period has not yet elapsed. Case No. U-21286 resulted in a settlement agreement that did not state the approved capital spending for all spending categories, and as such, imputed values are included.

Q. Please describe Exhibit A-17 (EWS-4).

A. Exhibit A-17 (EWS-4) provides a summary of historical and projected capital spend similar to Exhibit A-7 (EWS-2), Schedule B5, but with additional data granularity, including cause type. Again, the capital spending included in Exhibit A-17 (EWS-4) is supported by several other Company witnesses within this proceeding.

U-21513: DEPRECIATION CASE

Q. Please describe the relevance of Case No. U-21513, as it relates to this proceeding.

A. On December 6, 2023, the Company made an application to the Commission, seeking approval to implement new depreciation rates and practices. The depreciation rates and practices proposed in Case No. U-21513 have not yet been approved or otherwise acted upon by the Commission.

Q. In which proceeding were UPPCO's current depreciation rates approved?

A. UPPCO's current depreciation rates were approved by the Commission in its December 6, 2018 order in Case No. U-18467.

Q. Which depreciation rates did the Company utilize in the development of revenue deficiency, as reflected by Schedule A1 of Exhibit A-7, in this proceeding?

A. UPPCO is required to include its currently approved depreciation rates in any request for rate relief. As a result, the depreciation rates utilized to develop total depreciation expense for the projected test year in this proceeding are equal to the rates approved by the Commission in its December 6, 2018 order in Case No. U-18467.

Q. Does the Company anticipate a Commission order approving new depreciation rates in Case No. U-21513 prior to the conclusion of this proceeding?

A. Yes.

Q. What is the impact on the total and retail revenue deficiency presented in this proceeding if the Company's proposed depreciation rates from Case No. U-21513 are approved by the Commission?

A. Exhibit A-36 (EWS-9), U-21513 Depreciation Case Summary Result, provides an alternate view of Schedule A1 and Schedule B1, including the impact of the Company's proposed depreciation rates in Case No. U-21513. Adoption of these proposed depreciation rates <u>decreases</u> the retail revenue deficiency by $378,653, ceteris paribus.

CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
***

In the matter of the application of	)	
UPPER PENINSULA POWER COMPANY	)	
for authority to increase its rates for the generation	)	Case No. U-21555
and distribution of electricity and other relief.	)	
	)	

DIRECT TESTIMONY AND EXHIBITS OF

NATASHA L. WONCH

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

March 21, 2024

QUALIFICATIONS

Q. Please state your name, business address and position.

A. My name is Natasha L Wonch. My business address is 1002 Harbor Hills Drive, Marquette, MI 49855. I am the Director of Finance and Accounting for Upper Peninsula Power Company ("UPPCO" or the "Company").

Q. For whom are you providing testimony?

A. I am providing testimony on behalf of UPPCO in support of its request for an increase in its retail electric rates.

Q. Please describe briefly your educational, professional, and utility background.

A. I have a Bachelor of Science in Accounting and Computer Information Systems from Northern Michigan University. I am a Certified Public Accountant licensed in the state of Michigan. I began my career in public accounting in 2008 and joined UPPCO in 2015 as Payroll Administrator. I transitioned throughout the organization before being promoted to Director of Finance and Accounting in 2022.

Q. Have you previously testified in any regulatory proceedings?

A. Yes. I have provided testimony in UPPCO's State Reliability Mechanism ("SRM") capacity charge case, Energy Waste Reduction ("EWR") reconciliation cases, and Case No. U-20276 (General Rate Case).

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present UPPCO's 2023 historical test year revenue requirement ending December 31, 2023 and the calculation of UPPCO's revenue requirement for the projected 12-month period ending December 31, 2025 ("projected test year").

Q. How is your direct testimony organized?

A. My direct testimony is organized in sections consistent with the topics I will be covering:

Revenue Requirement Exhibits

Projected Test Year Financial Metrics

Projected Test Year Rate Base

Projected Test Year Operating Income

2023 Historical Test Year Revenue Sufficiency

2023 Historical Test Year Financial Metrics

2023 Historical Test Year Rate Base

2023 Historical Test year Operating Income

REVENUE REQUIREMENT EXHIBITS

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. For the historical 2023 test year, I am sponsoring the following exhibits:

1. Exhibit A-1 (NLW-1 through NLW-2), Schedules A1 through A2,
2. Exhibit A-2 (NLW-3 through NLW-6), Schedules B1 through B4, and
3. Exhibit A-3 (NLW-7 through NLW-17), Schedules C1 through C11.

For the projected test year, I am sponsoring the following exhibits:

4. Exhibit A-6 (NLW-18), Schedules A2,
5. Exhibit A-7 (NLW-19 through NLW-22), Schedules B1 through B4, and
6. Exhibit A-8 (NLW-23 through NLW-33), Schedules C1 through C11.
7. Exhibit A-15 (NLW-34), Depreciation & Amortization Expense

Q. Are you sponsoring any other exhibits?

A. No.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes, they were.

Q. Please describe Schedule A1 of Exhibit A-1 (NLW-1).

A. Schedule A1 of Exhibit A-1 (NLW-1) calculates UPPCO's 2023 historical test year revenue sufficiency based on its 13-month average rate base, adjusted net operating income, rate of return, and revenue conversion factor.

Q. Please describe Schedule A2 of Exhibit A-1 (NLW-2).

A. Schedule A2 of Exhibit A-1 (NLW-2) calculates UPPCO's historical financial metrics on both a financial basis and ratemaking basis from 2019 through 2023.

Q. Please describe Schedule B1 of Exhibit A-2 (NLW-3).

A. Schedule B1 of Exhibit A-2 (NLW-3) calculates UPPCO's 2023 historical test year rate base.

Q. Please describe Schedule B2 of Exhibit A-2 (NLW-4).

A. Schedule B2 of Exhibit A-2 (NLW-4) calculates UPPCO's 2023 historical test year utility plant.

Q. Please describe Schedule B3 of Exhibit A-2 (NLW-5).

A. Schedule B3 of Exhibit A-2 (NLW-5) depicts UPPCO's 2023 historical test year accumulated provision for depreciation.

Q. Please describe Schedule B4 of Exhibit A-2 (NLW-6).

A. Schedule B4 of Exhibit A-2 (NLW-6) calculates UPPCO's 2023 historical test year working capital.

Q. Please describe Schedule C1 of Exhibit A-3 (NLW-7).

A. Page 1 of Schedule C1 of Exhibit A-3 (NLW-7) calculates UPPCO's 2023 historical test year adjusted net operating income. Page 2 of Schedule C1 of Exhibit A-3 (NLW-7) calculates UPPCO's 2023 historical test year interest synchronization.

Q. Please describe Schedule C2 of Exhibit A-3 (NLW-8).

A. Schedule C2 of Exhibit A-3 (NLW-8) calculates UPPCO's 2023 historical test year gross revenue conversion factor.

Q. Please describe Schedule C3 of Exhibit A-3 (NLW-9).

A. Schedule C3 of Exhibit A-3 (NLW-9) calculates UPPCO's 2023 historical test year total revenue.

Q. Please describe Schedule C4 of Exhibit A-3 (NLW-10).

A. Schedule C4 of Exhibit A-3 (NLW-10) calculates UPPCO's 2023 historical test year total fuel and purchased power cost.

Q. Please describe Schedule C5 of Exhibit A-3 (NLW-11).

A. Schedule C5 of Exhibit A-3 (NLW-11) calculates UPPCO's 2023 historical test year total operation and maintenance ("O&M") expense.

Q. Please describe Schedule C6 of Exhibit A-3 (NLW-12).

A. Schedule C6 of Exhibit A-3 (NLW-12) depicts UPPCO's 2023 historical test year total depreciation and amortization expense.

Q. Please describe Schedule C7 of Exhibit A-3 (NLW-13).

A. Schedule C7 of Exhibit A-3 (NLW-13) calculates UPPCO's 2023 historical test year total for taxes other than income taxes.

Q. Please describe Schedule C8 of Exhibit A-3 (NLW-14).

A. Schedule C8 of Exhibit A-3 (NLW-14) depicts UPPCO's 2023 historical test year federal income taxes.

Q. Please describe Schedule C9 of Exhibit A-3 (NLW-15).

A. Schedule C9 of Exhibit A-3 (NLW-15) depicts UPPCO's 2023 historical test year state income taxes.

Q. Please describe Schedule C10 of Exhibit A-3 (NLW-16).

A. Schedule C10 of Exhibit A-3 (NLW-16) depicts UPPCO's 2023 historical test year local taxes.

Q. Please describe Schedule C11 of Exhibit A-3 (NLW-17).

A. Schedule C11 of Exhibit A-3 (NLW-17) depicts UPPCO's 2023 historical test year Allowance for Funds Used During Construction ("AFUDC").

Q. Please describe Schedule A2 of Exhibit A-6 (NLW-18).

A. Schedule A2 of Exhibit A-6 (NLW-18) calculates UPPCO's projected test year financial metrics absent rate relief and with full rate relief.

Q. Please describe Schedule B1 of Exhibit A-7 (NLW-19).

A. Schedule B1 of Exhibit A-7 (NLW-19) calculates UPPCO's projected 13-month average test year rate base.

Q. Please describe Schedule B2 of Exhibit A-7 (NLW-20).

A. Schedule B2 of Exhibit A-7 (NLW-20) calculates UPPCO's projected 13-month average test year utility plant.

Q. Please describe Schedule B3 of Exhibit A-7 (NLW-21).

A. Schedule B3 of Exhibit A-7 (NLW-21) depicts UPPCO's projected 13-month average test year accumulated provision for depreciation.

Q. Please describe Schedule B4 of Exhibit A-7 (NLW-22).

A. Schedule B4 of Exhibit A-7 (NLW-22) calculates UPPCO's projected 13-month average test year working capital.

Q. Please describe Schedule C1 of Exhibit A-8 (NLW-23).

A. Schedule C1 of Exhibit A-8 (NLW-23) calculates UPPCO's projected test year adjusted net operating income and interest synchronization calculation.

Q. Please describe Schedule C2 of Exhibit A-8 (NLW-24).

A. Schedule C2 of Exhibit A-8 (NLW-24) calculates UPPCO's projected test year gross revenue conversion factor.

Q. Please describe Schedule C3 of Exhibit A-8 (NLW-25).

A. Schedule C3 of Exhibit A-8 (NLW-25) calculates UPPCO's projected test year total revenue.

Q. Please describe Schedule C4 of Exhibit A-8 (NLW-26).

A. Schedule C4 of Exhibit A-8 (NLW-26) calculates UPPCO's projected test year total fuel and purchased power cost.

Q. Please describe Schedule C5 of Exhibit A-8 (NLW-27).

A. Schedule C5 of Exhibit A-8 (NLW-27) calculates UPPCO's projected test year total O&M expense.

Q. Please describe Schedule C6 of Exhibit A-8 (NLW-28).

A. Schedule C6 of Exhibit A-8 (NLW-28) depicts UPPCO's projected test year total depreciation and amortization expense.

Q. Please describe Schedule C7 of Exhibit A-8 (NLW-29).

A. Schedule C7 of Exhibit A-8 (NLW-29) calculates UPPCO's projected test year total for taxes other than income taxes.

Q. Please describe Schedule C8 of Exhibit A-8 (NLW-30).

A. Schedule C8 of Exhibit A-8 (NLW-30) depicts UPPCO's projected test year federal income taxes.

Q. Please describe Schedule C9 of Exhibit A-8 (NLW-31).

A. Schedule C9 of Exhibit A-8 (NLW-31) depicts UPPCO's projected test year state income taxes.

Q. Please describe Schedule C10 of Exhibit A-8 (NLW-32).

A. Schedule C10 of Exhibit A-8 (NLW-32) depicts UPPCO's projected test year local taxes.

Q. Please describe Schedule C11 of Exhibit A-8 (NLW-33).

A. Schedule C11 of Exhibit A-8 (NLW-33) depicts UPPCO's projected test year AFUDC.

PROJECTED TEST YEAR FINANCIAL METRICS

Q. Please explain Schedule A2, pages 1 through 3, of Exhibit A-6 (NLW-18).

A. Schedule A2, page 1 of Exhibit A-6 (NLW-18) develops financial metrics on a ratemaking basis for UPPCO's projected test year. Absent rate relief, UPPCO's earned rate of return on common equity would be 3.27% as evidenced on line 14.

Schedule A2, page 2 of Exhibit A-6 (NLW-18) develops additional financial metrics on a ratemaking basis for UPPCO's projected test year. The following items metrics are calculated (a) absent rate relief, and (b) with full rate relief:

1. EBIT Interest Coverage Ratio, as evidenced on line 20.
    a. Absent rate relief: 1.89
    b. With full rate relief: 3.90
2. EBITDA Interest Coverage Ratio, as evidenced on line 25.
    a. Absent rate relief: 3.53
    b. With full rate relief: 5.54
3. Funds Flow from Operations (FFO) Interest Coverage Ratio, as evidenced on line 35.
    a. Absent rate relief: 4.52
    b. With full rate relief: 6.44
4. Overall Fixed Charge Coverage Ratio, as evidenced on line 42.
    a. Absent rate relief: 1.67
    b. With full rate relief: 3.18

Schedule A2, page 3 of Exhibit A-6 (NLW-18) develops additional financial metrics on a ratemaking basis for UPPCO's projected test year. The following metrics are calculated (a) absent rate relief, and (b) with full rate relief:

1. Cash Flow Coverage of Dividend Ratio, as evidenced on line 48.
    a. Absent rate relief: Not applicable, no common dividends.
    b. With full rate relief: Not applicable, no common dividends.
2. Common Dividend Payout Ratio, as evidenced on line 51.
    a. Absent rate relief: Not applicable, no common dividends.

b. With full rate relief: Not applicable, no common dividends.

3. Permanent Capitalization, as evidenced on line 55.

   a. Absent rate relief: 337,827,614

   b. With full rate relief: 337,827,614

PROJECTED TEST YEAR RATE BASE

Q. Please explain Schedule B1 of Exhibit A-7 (NLW-19).

A. Schedule B1 of Exhibit A-7 (NLW-19) calculates UPPCO's projected test year rate base. The projected test year total company rate base is 387,512,056, and the projected test year Michigan retail rate base is 382,710,728, as shown on line 21. As shown on the schedule, the component parts are taken form the various sources indexed to the left of each value. All values shown are 13-month averages.

Q. Please explain Schedule B2 of Exhibit A-7 (NLW-20).

A. Schedule B2 of Exhibit A-7 (NLW-20) depicts UPPCO's projected test year utility plant. To arrive at the projected test year utility plant, the 2023 actual balance of utility plant was projected forward using UPPCO's projected 2024 through 2025 construction budgets. The projected test year total company utility plant is 504,151,351, and the projected test year Michigan retail utility plant is 497,396,910, as shown in line 13. All values shown are 13-month averages.

Q. Please explain Schedule B3 of Exhibit A-7 (NLW-21).

A. Schedule B3 of Exhibit A-7 (NLW-21) depicts UPPCO's projected test year accumulated provision for depreciation. To arrive at the projected test year accumulated provision for depreciation, the 2023 actual balance of accumulated provision for depreciation was projected forward using UPPCO's 2024 through 2025 construction budgets. The projected test year total company accumulated provision for depreciation is 206,622,026, and the projected test year Michigan retail accumulated provision for depreciation is 203,973,423 as shown on line 2. All values shown are 13-month averages.

Q. Please explain Schedule B4 of Exhibit A-7 (NLW-22).

A. Schedule B4 of Exhibit A-7 (NLW-22) calculates UPPCO's projected test year working capital. The projected test year total company working capital is 89,982,730, and the projected test year Michigan retail working capital is 89,287,241 as shown on line 37. All values shown are 13-month averages.

PROJECTED TEST YEAR OPERATING INCOME

Q. Please explain Schedule C1 of Exhibit A-8 (NLW-23).

A. Schedule C1 of Exhibit A-8 (NLW-23) calculates UPPCO's projected test year adjusted net operating income. The projected test year total company adjusted net operating income is 14,284,396 and the projected test year Michigan retail adjusted net operating income is 14,886,919 as shown on Line 22. The interest synchronization calculation is shown on page 2 of Schedule C1 of Exhibit A-8 (NLW-23).

Q. Please explain Schedule C2 of Exhibit A-8 (NLW-24).

A. Schedule C2 of Exhibit A-8 (NLW-24) calculates UPPCO's projected test year gross revenue conversion factor. The projected test year gross revenue conversion factor is 1.3288 as shown on line 16.

Q. Please explain Schedule C3 of Exhibit A-8 (NLW-25).

A. Schedule C3 of Exhibit A-8 (NLW-25) calculates UPPCO's projected test year total revenue. The projected test year total company revenues are 116,431,780, and the projected test year Michigan retail total revenue is 116,426,967 as shown on line 6.

Q. Please explain Schedule C4 of Exhibit A-8 (NLW-26).

A. Schedule C4 of Exhibit A-8 (NLW-26) calculates UPPCO's projected test year total fuel and purchased power cost of 35,861,299 as shown on line 6.

Q. Please explain Schedule C5 of Exhibit A-8 (NLW-27).

A. Schedule C5 of Exhibit A-8 (NLW-27) calculates UPPCO's projected test year total O&M expense, exclusive of fuel and purchased power. The projected test year total company O&M expense is 41,360,854 and the projected test year Michigan retail total O&M expense is 40,823,369 as shown on line 11.

Q. Please explain Schedule C6 of Exhibit A-8 (NLW-28).

A. Schedule C6 of Exhibit A-8 (NLW-28) depicts UPPCO's projected test year total depreciation and amortization expense. The projected test year total company total depreciation and amortization expense is 13,954,055, and the projected test year Michigan retail total depreciation and amortization expense is 13,771,323 as shown on line 6. Depreciation on line 3 was calculated based upon projected plant balances and closings for the projected test year, using the depreciation rates approved in Case No. U-18467.

Q. Please explain Schedule C7 of Exhibit A-8 (NLW-29).

A. Schedule C7 of Exhibit A-8 (NLW-29) depicts UPPCO's projected test total for taxes other than income taxes. The projected test year total company total taxes other than income taxes is 9,058,019, and the projected test year Michigan retail total taxes other than income taxes is 8,938,551 as shown on line 29.

Q. Please explain Schedule C8 of Exhibit A-8 (NLW-30).

A. Schedule C8 of Exhibit A-8 (NLW-30) depicts UPPCO's projected test year federal income taxes. The projected test year total company federal income taxes are 1,589,227, and the projected test year Michigan retail income taxes are 1,776,469 as shown on line 14.

Q. Please explain Schedule C9 of Exhibit A-8 (NLW-31).

A. Schedule C9 of Exhibit A-8 (NLW-31) depicts UPPCO's projected test year state income taxes. The projected test year total company state income taxes are 362,579 and the projected test year Michigan retail state income taxes are 407,172 as shown on line 14.

Q. Please explain Schedule C10 of Exhibit A-8 (NLW-32).

A. Schedule C10 of Exhibit A-8 (NLW-32) depicts UPPCO's projected test year local taxes. The projected test year total company local taxes are $0, as shown in the exhibit.

Q. Please explain Schedule C11 of Exhibit A-8 (NLW-33).

A. Schedule C11 of Exhibit A-8 (NLW-33) depicts UPPCO's projected test year AFUDC. The projected test year total company AFUDC Debt is $0 and the projected test year Michigan retail AFUDC Debt is $0 as shown on line 5.

Q. Please explain Exhibit A-15 (NLW-34), Depreciation & Amortization Expense.

A. As represented in Schedule C6 of Exhibit A-8 (NLW-28), depreciation expense for the projected test year ending December 31, 2025 is $11,422,213, while amortization expense is $2,531,842.

2023 HISTORICAL TEST YEAR REVENUE DEFICIENCY (SUFFICIENCY)

Q. Please explain Schedule A1 of Exhibit A-1 (NLW-1).

A. Schedule A1 of Exhibit A-1 (NLW-1) calculates UPPCO's historical 2023 test year revenue deficiency (sufficiency) based on its rate base, adjusted net operating income, rate of return and revenue conversion factor. This schedule indicates that the 2023 total company revenue sufficiency is $14,203,711, and the 2023 Michigan retail revenue sufficiency is $14,230,156. As shown on the schedule, the component parts are taken form the various sources indexed to the left of each value.

2023 HISTORICAL TEST YEAR FINANCIAL METRICS

Q. Please explain Schedule A2, pages 1 through 4, of Exhibit A-1 (NLW-2).

A. Schedule A2, page 1 of Exhibit A-1 (NLW-2) depicts financial metrics on a financial basis for 2019 through 2023. For this period, UPPCO's earned rate of return on common equity was 6.19%, 7.58%, 9.36%, 3.51%, and 5.03% as seen on line 12.

Schedule A2, page 2 of Exhibit A-1 (NLW-2) depicts additional financial metrics on a financial basis for 2019 through 2023, calculating the EBIT Interest Coverage Ratio on line 19, the EBITDA Interest Coverage Ratio on line 24, and the Funds Flow from Operations (FFO) Interest Coverage Ratio on line 35.

Schedule A2, page 3 of Exhibit A-1 (NLW-2) depicts additional financial metrics on a financial basis for 2019 through 2023, calculating the Overall Fixed Charge Coverage Ratio on line 42, the Cash Flow Coverage of Dividends Ratio on line 48, the Common Dividend Payout Ratio on line 51, and Permanent Capitalization on line 59.

Schedule A2, page 4 of Exhibit A-1 (NLW-2) depicts additional financial metrics on a ratemaking basis for 2019 through 2023. For this period, UPPCO's earned rate of return on common equity was 8.18%, 9.05%, 8.53%, 3.91%, and 7.88% as seen on line 73.

Schedule A2, page 5 of Exhibit A-1 (NLW-2) depicts additional financial metrics on a ratemaking basis for 2019 through 2023, calculating the EBIT Interest Coverage Ratio on line 79, the EBITDA Interest Coverage Ratio on line 84, and the Funds Flow from Operations (FFO) Interest Coverage Ratio on line 95.

Schedule A2, page 6 of Exhibit A-1 (NLW-2) depicts additional financial metrics on a ratemaking basis for 2019 through 2023, calculating the Cash Flow Coverage of Dividends Ratio on line 108, the Common Dividend Payout Ratio on line 111, and Permanent Capitalization on line 119.

2023 HISTORICAL TEST YEAR RATE BASE

Q. Please explain Schedule B1 of Exhibit A-2 (NLW-3).

A. Schedule B1 of Exhibit A-2 (NLW-3) calculates UPPCO's 2023 historical test year rate base. The 2023 total company rate base is $331,309,864, and the 2023 Michigan retail rate base is $327,377,442, as shown on line 21. As seen on the schedule, the component parts are taken form the various sources indexed to the left of each value. All values shown are 13-month averages.

Q. Please explain Schedule B2 of Exhibit A-2 (NLW-4).

A. Schedule B2 of Exhibit A-2 (NLW-4) depicts UPPCO's 2023 historical test year utility plant. The 2023 total company utility plant is $429,945,136, and the 2023 Michigan retail utility plant is $424,444,465, as shown on line 13. All values shown are 13-month averages.

Q. Please explain Schedule B3 of Exhibit A-2 (NLW-5).

A. Schedule B3 of Exhibit A-2 (NLW-5) depicts UPPCO's 2023 historical test year accumulated provision for depreciation. The 2023 total company accumulated provision for depreciation is $183,228,722, and the 2023 Michigan retail accumulated provision for depreciation is $181,039,467 as shown on line 2. All values shown are 13-month averages.

Q. Please explain Schedule B4 of Exhibit A-2 (NLW-6).

A. Schedule B4 of Exhibit A-2 (NLW-6) calculates UPPCO's 2023 historical test year working capital. The 2023 total company working capital is $84,593,451, and the 2023

Michigan retail working capital is $83,972,444 as shown on line 37. All values shown are 13-month averages.

2023 HISTORICAL TEST YEAR OPERATING INCOME

Q. Please explain Schedule C1 of Exhibit A-3 (NLW-7).

A. Schedule C1 of Exhibit A-3 (NLW-7) calculates UPPCO's 2023 historical test year adjusted net operating income. The 2023 total company adjusted net operating income is $11,514,331 and the 2023 Michigan retail adjusted net operating income is $11,241,575 as shown on line 22. The interest synchronization calculation is shown on page 2 of Schedule C1 of Exhibit A-3 (NLW-7).

Q. Please explain Schedule C2 of Exhibit A-3 (NLW-8).

A. Schedule C2 of Exhibit A-3 (NLW-8) calculates UPPCO's 2023 historical test year gross revenue conversion factor. The 2023 gross revenue conversion factor is 1.3288.

Q. Please explain Schedule C3 of Exhibit A-3 (NLW-9).

A. Schedule C3 of Exhibit A-3 (NLW-9) calculates UPPCO's 2023 historical test year total revenue. The 2023 total company revenues are $108,785,355, and the 2023 Michigan retail total revenue is $107,720,273 as shown on line 6.

Q. Please explain Schedule C4 of Exhibit A-3 (NLW-10).

A. Schedule C4 of Exhibit A-3 (NLW-10) calculates UPPCO's 2023 historical test year total fuel and purchased power cost of $39,318,152 as shown on line 6.

Q. Please explain Schedule C5 of Exhibit A-3 (NLW-11).

A. Schedule C5 of Exhibit A-3 (NLW-11) calculates UPPCO's 2023 historical test year total O&M expense, exclusive of fuel and purchased power. The 2023 total company O&M expense is $37,229,725 and the 2023 Michigan retail total O&M expense is $36,757,793 as shown on line 11.

Q. Please explain Schedule C6 of Exhibit A-3 (NLW-12).

A. Schedule C6 of Exhibit A-3 (NLW-12) depicts UPPCO's 2023 historical test year total depreciation and amortization expense. The 2023 total company total depreciation and amortization expense is $12,587,076, and the 2023 Michigan retail total depreciation and amortization expense is $12,427,434 as shown on line 6. Depreciation on line 3 was calculated based upon the depreciation rates approved in Case No. U-18467.

Q. Please explain Schedule C7 of Exhibit A-3 (NLW-13).

A. Schedule C7 of Exhibit A-3 (NLW-13) depicts UPPCO's 2023 historical test year total for taxes other than income taxes. The 2023 total company total taxes other than income taxes is $8,184,174, and the 2023 Michigan retail total for taxes other than income taxes is $8,082,104 as shown on line 29.

Q. Please explain Schedule C8 of Exhibit A-3 (NLW-14).

A. Schedule C8 of Exhibit A-3 (NLW-14) depicts UPPCO's 2023 historical test year federal income taxes. The 2023 total company federal income taxes are $(186,059), and the 2023 Michigan retail income taxes are $(233,893) as shown on line 14.

Q. Please explain Schedule C9 of Exhibit A-3 (NLW-15).

A. Schedule C9 of Exhibit A-3 (NLW-15) depicts UPPCO's 2023 historic test year state income taxes. The 2023 total company state income taxes are $177,457 and the 2023 Michigan retail state income taxes are $166,091 as shown on line 14.

Q. Please explain Schedule C10 of Exhibit A-3 (NLW-16).

A. Schedule C10 of Exhibit A-3 (NLW-16) depicts UPPCO's 2023 historical test year local taxes. The 2023 total company local taxes are $0, as shown in the exhibit.

Q. Please explain Schedule C11 of Exhibit A-3 (NLW-17).

A. Schedule C11 of Exhibit A-3 (NLW-17) depicts UPPCO's 2023 historic test year AFUDC. The 2023 total company AFUDC is $0 as shown on line 5.

CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
***

In the matter of the application of	**)**	
UPPER PENINSULA POWER COMPANY	**)**	
for authority to increase its rates for the generation	**)**	Case No. U-21555
and distribution of electricity and other relief.	**)**	
	)	

DIRECT TESTIMONY AND EXHIBITS OF

NICHOLAS E. KATES

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

[PUBLIC - REDACTED]

March 21, 2024

QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Nicholas E. Kates. My business address is 1002 Harbor Hills Drive, Marquette, MI 49855.

Q. By whom are you employed and in what capacity?

A. I am the Chief Financial Officer ("CFO") for Upper Peninsula Power Company ("UPPCO" or the "Company").

Q. Please summarize your background.

A. I have a Bachelor of Science in Accounting and a Master of Business Administration from Millikin University. I began my career in public accounting in 1991 and have held various accounting, finance and information technology roles in manufacturing, financial services, and electric utility organizations, culminating with my role as Business Unit Chief Financial Officer of DSM Functional Materials prior to joining UPPCO as Chief Financial Officer in 2015. In March 2020 I left UPPCO, taking the role of CFO of a financial services organization. I subsequently returned to the role of CFO at UPPCO in May of 2023. My primary accountabilities include leading the accounting, finance, tax, corporate reporting, financial planning, information technology, cyber security, and customer service functions for UPPCO.

Q. Have you previously testified in any regulatory proceedings?

A. Yes. I have testified before the Michigan Public Service Commission ("MPSC" or the "Commission") in Case No. U-20276.

PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony in this proceeding?

A. I will provide testimony in the following areas: (1) explanation of UPPCO's forecasted adjustments and inputs, (2) recommendations regarding the capital structure and cost of capital utilized in the computation of UPPCO's overall rate of return for the projected test year, and (3) explanation of UPPCO's Information Technology ("IT") capital projects.

Q. How is your direct testimony organized?

A. My direct testimony is organized in sections consistent with the topics I will be covering, as listed below:

Section I: Forecast Adjustments

Section II: Capital Structure

Section III: Information Technology Capital Projects

Q. Are you sponsoring any exhibits related to your direct testimony?

A. Yes.

Q. Please identify the exhibits you are sponsoring

A. I am sponsoring the following exhibits:

- Exhibit A-4, Schedule D1 (NEK-1), Historical Rate of Return Summary
- Exhibit A-4, Schedule D2 (NEK-2), Historical Cost of Long-Term Debt
- Exhibit A-4, Schedule D3 (NEK-3), Historical Cost of Short-Term Debt
- Exhibit A-4, Schedule D4 (NEK-4), Historical Cost of Preferred Stock

- Exhibit A-4, Schedule D5 (NEK-5), Historical Cost of Common Shareholders' Equity
- Exhibit A-9, Schedule D1 (NEK-6), Projected Rate of Return Summary
- Exhibit A-9, Schedule D2 (NEK-7), Projected Cost of Long-Term Debt
- Exhibit A-9, Schedule D3 (NEK-8), Projected Cost of Short-Term Debt
- Exhibit A-9, Schedule D4 (NEK-9), Projected Cost of Preferred Stock
- Exhibit A-9, Schedule D5 (NEK-10), Projected Cost of Common Shareholders' Equity
- Exhibit A-12 (NEK-11), Forecast Adjustments/Inputs Summary
- Exhibit A-14 (NEK-12), Bad Debt Expense
- Exhibit A-16 (NEK-13), Pension & OPEB Expense
- Exhibit A-22 (NEK-14), UPPCO Information Technology CAPEX
- Exhibit A-37 (NEK-15), Willis Towers Watson Report
- Exhibit A-38 (NEK-16), U-20757 Deferred Uncollectible
- Exhibit A-39 (NEK-17), Revolver Calculation
- Exhibit A-40 (NEK-18), Free Cash Flow
- Exhibit A-41 (NEK-19), WTW Welfare Expense Report
- Exhibit A-42 (NEK-20), WTW Pension Expense Report

I am also referencing the following exhibit that is sponsored by Company witness Jay R. Ringler.

- Exhibit A-13 (JRR-2)

SECTION I: PROJECTED TEST YEAR FORECAST ADJUSTMENTS/INPUTS

Q. Please describe how the Company's projected test year revenue requirement ending December 31, 2025 is developed?

A. As discussed by Company witness Stocking, UPPCO's methodology utilized a historical 2023 test year. UPPCO then escalated the historical 2023 costs by expense specific inflationary rates, specific known and measurable differences where appropriate, and core inflation to derive projected test year values. To achieve these modeled results, UPPCO applied these adjustments for the years 2024 and 2025 to calculate the value representing the January 1, 2025, through December 31, 2025 projected test year.

Q. How does UPPCO present its forecast adjustments/inputs for the projected test year ending December 31, 2025?

A. Please find Exhibit A-12 (NEK-11), Forecast Adjustments/Inputs Summary.

Q. Please explain Forecast Adjustment 1 as evidenced in Exhibit A-12 (NEK-11), Inflation Factor.

A. UPPCO applied an annual core inflation factor of 2.7% and 2.4% for 2024 and 2025, respectively, to derive its projected test year costs. The source for these projections was the core CPI rates for 2024 and 2025 as published in the Congressional Budget Office ("CBO") report for February 2022[1], titled, *The Budget and Economic Outlook: 2022 to 2032*. This source is reasonable because the CBO provides nonpartisan analysis on budgetary and economic issues for the United States Congress. UPPCO is utilizing the

[1] The Budget and Economic Outlook: 2022 to 2032 | Congressional Budget Office (cbo.gov)

CBO's forecast for the Core Consumer Price Index which is a reasonable proxy for inflation.

Q. Please explain Forecast Adjustment 2 as evidenced in Exhibit A-12 (NEK-11), Percent Salary & Wage (S&W) Adjustment - Union

A. UPPCO applied a wage and salary adjustment of [redacted] for its union workforce. These rates are consistent with the UPPCO Local Union No. 510 Collective Bargaining Agreement ("CBA") effective April 16, 2023 through April 18, 2026, and in line with United States salary and wage increases as published by the CBO in their February 2024 report

Percent Wage & Salary Increase - Union					
Average Line Electrician Wage Data					
	Actual			Forecast	
	2021	2022	2023	2024	2025
UPPCO ($s)	$ 43.59	$ 44.90	$ 49.94	$ [redacted]	[redacted]
UPPCO Union Wage Increase		3.01%	11.23%	[redacted]	[redacted]
UPPCO Cumulative Change since 2021			14.57%	[redacted]	[redacted]
CBO Wages & Salaries (Billions of $s)	10,312.6	11,116.0	11,807.6	12,375.8	12,951.6
CBO % change		7.79%	6.22%	4.81%	4.65%
CBO Cumulative Change since 2021			14.01%	18.82%	23.48%
UPPCO cumulative change versus market (CBO)			**0.56%**	[redacted]	[redacted]

Again, this source is reasonable because the CBO provides nonpartisan analysis on budgetary and economic issues for the United States Congress.

Q. Please explain Forecast Adjustment 3 as evidenced in Exhibit A-12 (NEK-11), Percent Salary & Wage (S&W) Adjustment - Non Union.

A. UPPCO applied the same [redacted] wage and salary adjustment for its non-union, administrative employees for the projected test year.

Percent Wage & Salary Increase - Non-Union (Administrative)					
	Actual			Forecast	
	2021	2022	2023	2024	2025
UPPCO Wages & Salaries Adjustment		3.50%	5.00%	[redacted]	[redacted]
UPPCO Cumulative Change since 2021		3.50%	8.50%	[redacted]	[redacted]
CBO Wages & Salaries (Billions of $s)	10,312.6	11,116.0	11,807.6	12,375.8	12,951.6
CBO % change		7.79%	6.22%	4.81%	4.65%
CBO Cumulative Change since 2021			14.01%	18.82%	23.48%
UPPCO cumulative change versus market (CBO)			**-5.51%**	[redacted]	[redacted]

Q. Please explain Forecast Adjustment 4 as evidenced in Exhibit A-12 (NEK-11), Distribution Line Clearance.

A. As described in the direct testimony and exhibits of Company witness Ringler, UPPCO operates on a six-year distribution line clearance program and evidences these expenditures on Exhibit A-13 (JRR-2), 6 Year Distribution Line Clearance Program. Since vegetation management and/or line clearance costs are recorded in FERC 593, the Company adjusts these figures by the inflation factor of 5.00% presented in row 4 of Exhibit A-12 (NEK-11).

Q. Please explain Forecast Input 5 as evidenced in Exhibit A-14 (NEK-12), Bad Debt Expense.

A. Bad debt expense is accounted for in FERC 904. To calculate UPPCO's bad debt expense for the projected test year ending December 31, 2025, UPPCO utilized a five-year trend value of actual, historical and projected values. Actual data was utilized from 2020 through 2023 and budgeted data for 2024. All values were averaged resulting in an inflation-adjusted value of $350,258 for 2025. In order to arrive at the Adjusted Bad Debt amount of $516,037 for 2025, the 2025 amortization of deferred bad debt amount of $165,779 ordered in U-20757 and further settled in U-21286 is added to the $350,258.

Q. Please explain Forecast Input 6 as evidenced in Exhibit A-16 (NEK-13), Pension & OPEB Expense.

A. Pensions are a type of employer-sponsored retirement plan. For the projected test year ending December 31, 2025, pension expenses are evidenced at line 6 of Exhibit A-16 (NEK-13), Total Pension expense. Other Post-Employment Benefits ("OPEB") expenses are typically the benefits (i.e., health, life insurance, etc.,), other than pension distributions, that employees may begin to receive from their employer once they retire. For the projected test year ending December 31, 2025, pension expenses are evidenced at line 12 of Exhibit A-16 (NEK-13), Total OPEB expense. Both pension and OPEB expenses are recorded in FERC 926. Willis Towers Watson US LLC ("WTW") was engaged by UPPCO to provide 2024 and 2025 forecasted benefit cost, based on the 2023 pension and postretirement welfare valuations, for rate case purposes. These valuations were performed in accordance with generally accepted actuarial principles and practices. Exhibit A-37 (NEK-15), Willis Towers Watson Report, provides the 2024 and 2025 budget estimates. This information was prepared in accordance with FASB ASC 715-30 and 715-60.

Assumptions and methods for 2024 and 2025 projects are as follows: (1) discount rates reflect market conditions as of September 30, 2023 with an increase of 0.5% assumed for 2024 and 2025; (2) actual return on assets for 2023 reflects actual trust returns through September 30, 2023 and assume 0.0% return for the remainder of 2023; (3) expected rate of return assumption for 2024 and 2025 is 5.50%; (4) contributions assumed in the forecast period for the 2024 and 2025 periods are: (i) Restoration, $29K for both periods, (ii) SERP, $12K for both periods, (iii) Administrative Medical, $38K and $41K, respectively, and (iv) Retiree Life Insurance, $122K in both periods; and (4) all other assumptions and methods were selected by UPPCO at year-end 2023 and are summarized in Appendix A of Exhibit A-41 (NEK-19), WTW Welfare Expense Report and Exhibit A-42 (NEK-20), WTW Pension Expense Report regarding the January 1, 2023, accounting valuation reports delivered on August 23, 2023. Except as otherwise provided herein, the results presented are based on the data, assumptions, methods, models, plan provisions and other information outlined in the actuarial valuation reports that set forth the pension and other postretirement benefit cost for the fiscal year beginning January 1, 2023.

For the projected test year ending December 31, 2025, UPPCO identifies its Other Benefits Expense and escalates them individually as appropriate with factors including contractual obligations and market dynamics specific to medical, dental, vision, short-term disability ("STD"), long-term disability ("LTD"), and life insurance.

SECTION II: CAPITAL STRUCTURE

Q. **Regarding the historical test year ending December 31, 2023, please explain Schedule D1 of Exhibit A-4 (NEK-1)**.

A. Schedule D1 develops UPPCO's historical test year overall rate of return of 6.72%, as shown at line 22, based on UPPCO's 13-month average capital structure, and a 9.9% ROE. As a percent of permanent capital, the 13-month historical debt and equity balances are 45.96% and 54.04%, respectively, as evidenced at lines 2 and 6.

Q. **Regarding the historical test year ending December 31, 2023, please explain Schedule D2 of Exhibit A-4 (NEK-2)**.

A. Schedule D2 develops UPPCO's historical test year cost of long-term debt of 4.27%, based on a 13-month average, as shown at line 24.

Q. Regarding the historical test year ending December 31, 20231, please explain Schedule D3 of Exhibit A-4 (NEK-3).

A. Schedule D3 develops UPPCO's historical test year cost of short-term debt of 7.09%, based on a 13-month average, as calculated at line 22.

Q. Regarding the historical test year ending December 31, 2023, please explain Schedule D4 of Exhibit A-4 (NEK-4).

A. Schedule D4 indicates that UPPCO has no preferred equity outstanding.

Q. Regarding the historical test year ending December 31, 2023, please explain Schedule D5 of Exhibit A-4 (NEK-5).

A. Schedule D5 develops UPPCO's 13-month average balance of Adjusted Common Equity of $149,467,560 for the historical test year, as shown on line 16 UPPCO demonstrates a 9.9% ROE for the historical test year.

Q. For the projected test year ending December 31, 2025, please explain Schedule D1 of Exhibit A-9 (NEK-6).

A. Schedule D1 develops UPPCO's projected test year overall rate of return of 7.02%, as shown at line 22, based on UPPCO's 13-month average capital structure, and a proposed 10.70% ROE. As a percent of permanent capital, the 13-month proposed debt and equity balances are 48.48% and 51.52%, respectively, as evidenced at lines 2 and 6. These balances are in alignment with the balances ordered in U-21286 and are achieved through UPPCO's debt recapitalization plan to be executed in September of 2024.

Q. Please explain UPPCO's debt recapitalization plan.

A. On September 30, 2024, UPPCO plans to convert existing, higher cost, short-term revolver financing with a balance of lower cost, long-term permanent debt and equity in order to achieve the ordered debt and equity ratios. UPPCO plans to issue $36,686,687 of long-term debt, while increasing common equity levels by $31,880,908 through an equity infusion at this same time. The revolver balance immediately after the debt recapitalization is planned to be $0.

Q. **For the projected test year ending December 31, 2025, please explain Schedule D2 of Exhibit A-9 (NEK-7)**.

A. Schedule D2 develops UPPCO's projected test year cost of long-term debt of 4.53%, based on a 13-month average, as shown at line 23. Long term debt cost is derived from the existing long-term notes in the amount of $127,100,000 issued June 3, 2021 at 3.59% and a newly issued long-term term loan in the amount of $36,686,687 to be issued September 30, 2024 with a projected test year rate of 5.43%. While the newly issued term loan at 5.93% [Schedule D1 of Exhibit A-9 (NEK-6)] will replace higher cost short-term revolver debt at 7.09% [Schedule D1 of Exhibit A-4 (NEK-1)], this action will provide immediate benefit to customers in the form of decreased interest expense on Company debt while retaining the flexibility to pivot to even lower cost debt in the future.

Q. **For the projected test year ending December 31, 2025, please explain Schedule D3 of Exhibit A-9 (NEK-8)**.

A. Schedule D3 develops UPPCO's projected test year cost of short-term debt of 5.93%, based on a 13-month average, as calculated at line 22. Please find Exhibit A-39 (NEK-17), Revolver Calculation, whereby UPPCO builds its projection of the 3-month Secured Overnight Financing Rate ("SOFR"). As evidenced in Exhibit A-39 (NEK-17), UPPCO utilized forecasted data from Canadian Imperial Bank of Commerce ("CIBC") and added the applicable margin rate of 1.625% to project January 2024 through December 2025 revolver rates.

Q. **For the projected test year ending December 31, 2025, please explain Schedule D4 of Exhibit A-9 (NEK-9)**.

A. Schedule D4 indicates that UPPCO has no preferred equity outstanding.

Q. **For the projected test year ending December 31, 2025, please explain Schedule D5 of Exhibit A-9 (NEK-10)**.

A. Schedule D5 develops UPPCO's 13-month average balance of Adjusted Common Equity of $174,040,926 for the projected test year, as shown on line 16. UPPCO requests a 10.7% ROE for the projected test year in this general rate case proceeding, as further supported by Company witness Thompson's direct testimony and exhibits.

Q. What capital structure are you recommending be utilized in the overall rate of return calculation?

A. I am recommending that the capital structure shown on Schedule D-1 of Exhibit A-9 (NEK-6) be used. This capital structure represents the actual capital structure as of December 31, 2023, adjusted for the projected changes in debt, equity, and deferred income taxes through the end of the projected test year ending on December 31, 2025.

The development of the capital structure on a ratemaking basis is shown in columns (b) through (d). The equity ratio as a percentage of permanent capital is 51.52%, while the debt ratio as a percentage of permanent capital is 48.48%, both of which are directly aligned with the Commission order approving settlement in Case No. U-21286. This common equity ratio is further supported by the direct testimony and exhibits of Company witness John Thompson

Q. What Return on Equity ("ROE") are you assuming to determine the overall cost of capital for UPPCO?

A. I am assuming an ROE for UPPCO of 10.70% as evidenced at line 6 of Schedule D1 of Exhibit A-9 (NEK-6). Again, this ROE is supported by Company witness Thompson in his direct testimony and exhibits.

Q. What is the overall rate of return for UPPCO that you recommend be used in this case?

A. I am recommending an overall rate of return of 7.02% on an after-tax basis. This overall rate of return is the result of utilizing the capital structure and cost rates shown on Schedule D1 of Exhibit A-9 (NEK-6) at line 22. The cost of the components and the weighted cost are shown in columns (e) through (i). The overall rate of return that I am recommending is the weighted cost of the various components of the capital structure.

Q. Please describe the development of UPPCO's capital structure.

A. Capital structure refers to the amounts and mix of a company's financing components which make up the funds used for its operations and capital investment. For the

Company, this includes long-term debt, common equity, short-term debt, and deferred income taxes.

Q. What is UPPCO's long-term debt and short-term debt.

A. Long-term debt consists of loans that have a due date or maturity that are more than one year from the date of issuance. For UPPCO, long-term debt consists of $127,100,000 of senior secured fixed rate notes with a 3.59% cost rate and a term of 30 years and a $36,686,687 term loan priced with a 125 bps spread over SOFR with a term of two years. Short-term debt represents borrowings that are short-term in nature or less than one year and include borrowings under the Company's credit facilities. For UPPCO, short-term debt currently consists of a $75,000,000 credit facility (capacity) at CIBC. UPPCO has assumed a 13-month balance of $18,952,008 for the projected test year as evidenced in Schedule D1 of Exhibit A-9 (NEK-6) at line 10.

Q. What is UPPCO's common equity?

A. Equity is the net worth or represents the value of a company's assets less their liabilities. Typically, common equity increases with net income and/or retained earnings as well as with equity contributions from a parent company or return of capital to a parent company. Also, common equity typically decreases when a company makes dividend distributions. For UPPCO, the assumed 13-month balance of common equity is $174,040,926 for the projected test year as evidenced in Schedule D1 of Exhibit A-9 (NEK-6) at line 6.

Q. Please explain how the Company manages its current and future financing requirements.

A. The Company generally prioritizes financing its long-term capital, such as plant and property, with long-term debt and equity. Also, UPPCO generally purposes to finance its short-term capital requirements, such as seasonal working capital needs or certain large capital projects expenditures, with short-term debt. As UPPCO approaches the $75,000,000 limit on its current revolver, the Company plans to roll the existing revolver into a new tranche of long-term debt and subsequently take out a new short-term credit facility.

Q. Are there any adjustments to the permanent capital structure from the historical test year through the end of the projected test year, December 31, 2025?

A. Yes. Based upon cash flow projections evidenced in Exhibit A-40 (NEK-18), as UPPCO approaches the limit on its current revolver in September of 2024, the Company will rebalance its debt and equity positions to achieve the agreed equity thickness of 51.5% by converting a portion of the existing revolver, $36,686,687, into long-term debt as shown on Schedule D2 of Exhibit A-9 (NEK-7), with the remaining balance of the existing revolver recapitalization coming from an equity infusion of $31,880,908, Exhibit A-40 (NEK-18).

Q. Are there any adjustments to the short-term credit facility from the historical test year through the end of the projected test year, December 31, 2025?

A. Yes. UPPCO's projected monthly revolver balance is presented in Exhibit A-39 (NEK-17), Free Cash Flow. UPPCO determines its monthly revolver balance by estimating the Company's free cash flow available for capital expenditures and accounting for any return of capital made to our parent, UPPHC.

Q. Please explain why UPPCO is projecting an increasing balance in its short-term credit facility.

A. UPPCO's capital expenditures are expected to be greater than its free cash flow. Free cash flow reflects the cash position of a company after it pays for its operating expenses and capital expenditures. To the extent that that UPPCO's capital expenditures exceed its free cash flow, UPPCO will generally utilize its short-term credit facility to temporarily fund the difference.

Q. Please explain how UPPCO customers benefit from this revolver capitalization?

A. First, a lower interest rate means lower interest expense. The long-term Term Loan will be priced at a spread to SOFR of 125-bps versus the revolving loan spread of 162.5-bps evidenced in Exhibit A-39 (NEK-16). Second, the equity infusion will relieve the balance of the existing revolver in order to facilitate a new revolver. This new $75,000,000 short-term revolving credit facility will allow for needed liquidity to fund the Company's ongoing operations.

Q. How does UPPCO plan to achieve the equity percentage of 51.5% as ordered in Case No. U-21286?

A. In September 2024 UPPCO will achieve the equity percentage of 51.5% ordered in Case No. U-21286 through the recapitalization of its currently existing revolving credit facility. As discussed earlier, Based upon cash flow projections evidenced in Exhibit A-40 (NEK-18), as UPPCO approaches the limit on its current revolver in September 2024, the Company will refinance the existing short-term revolver debt into both debt and equity positions to achieve the agreed equity percentage of 51.5% by converting a portion of the existing revolver, $36,686,687 (53.5% of the refinanced debt), into long-term debt as shown on Schedule D2 of Exhibit A-9 (NEK-7), with the remaining balance of the existing revolver recapitalization coming from an equity infusion of $31,880,908 (46.5% of the refinanced debt), Exhibit A-40 (NEK-18). By weighting the recapitalization of the outstanding existing short-term revolver debt more heavily toward long-term permanent debt versus equity, and in conjunction with quarterly returns of capital to UPPHC, UPPCO will achieve the ordered equity percent of 51.5% at the time of the recapitalization.

UPPCO will maintain an equity percentage of 51.5% going forward through quarterly returns of capital and equity infusions as necessary per Exhibit A-40 (NEK-18).

Q. Upon completion of the revolver recapitalization in 2024, by how much will UPPCO have reduced its equity thickness since December 2023?

A. In compliance with U-21286, UPPCO will achieve an equity thickness of 51.5% with the completion of its revolving credit recapitalization in 2024, a 252-bps reduction since December of 2023.

Q. Please explain how UPPCO is accounting for justifiable IRP-related costs.

A. Pursuant to the final Commission Order Approving Settlement Agreement issued February 6, 2020 in Case No. U-20350, UPPCO continues to record all justifiable IRP related costs in FERC Account 183. Paragraph 19.i. of the settlement agreement in Case No. U-20350 states the following:

> *"UPPCO will be allowed to defer for consideration in UPPCO's next rate case all justifiable IRP related costs recorded in*

UPPCO's FERC Account 183, pursuant to Section 6t of 2016 PA 341, MCL 460.6t, and all other applicable laws."

UPPCO is currently in the process of developing its 62.5 MW solar facility, and the Company has not yet determined *"all justifiable IRP related costs."* As such, the Company respectfully requests that Commission authorize UPPCO to continue to allow deferral of all justifiable IRP related costs in FERC Account 183 for consideration in UPPCO's next rate case.

SECTION III: INFORMATION TECHNOLOGY CAPITAL PROJECTS

Q. Is the Company planning information technology projects that support business operations for UPPCO?

A. Yes. These projects are evidenced in Exhibit A-22 (NEK-14), Information Technology CAPEX.

Q. Why is UPPCO's proposed information technology spend critical to the Company's success?

A. Many of the challenges that businesses face today, including UPPCO, center on keeping existing technologies safe, effective, and relevant for utility and business operations, while developing and building new digital capabilities to support the continued modernization of the electric grid and increased data utilized for improved decision-making both by the Company and its customers.

Q. How is UPPCO's IT department structured?

A. UPPCO's IT department is tasked with maintaining reliable and secure IT solutions that serve and support UPPCO's many business functions. These functions include, but are not limited to, supporting the following platforms and/or services: (1) cyber security for the entire business, (2) continued improvement and maintenance of our Advanced Metering Infrastructure ("AMI"), and the operationalization of AMI data, (3) Supervisory Control and Data Acquisition ("SCADA"), (4) Enterprise Resource Planning ("ERP") for customer service and financial systems of record, (5) Geographic Information System ("GIS"), and (6) various operational technologies utilized in the field. In addition, further support functions include day-to-day operational support of end-user technologies such as desktop, laptop, and various mobile devices.

Q. Please explain the nature of the IT capital project on line 1 of Exhibit A-22 (NEK-14)?

A. As with any utility or business, UPPCO's IT department maintains a large and complex infrastructure which provides the backbone for essentially all activities that take place within the organization, from dispatching linemen to address emergency outages, designing distribution networks for line extensions for new customers, or billing and customer service operations. The makeup for this backbone is physical hardware and appliances, including, servers, routers, switches, desktop computers, mobile laptop computers, security camara equipment, and other network infrastructure appliances that enable a utility's required applications. This line items represents the costs for this new and replacement infrastructure hardware.

Q. Please explain why the capital spending on line 1 of Exhibit A-22 (NEK-14) is needed?

A. UPPCO maintains a record of installed inventory of hardware infrastructure currently in place throughout its network and tracks the vintage of the physical equipment for purposes of adhering to a scheduled replacement cycle. The Company has established specific replacement cycles for equipment depending upon the equipment's purpose and expected useful life. This best practice is employed in order to avoid emergency downtime of essential elements of the utilities IT operations that would have a deleterious impact to operations and our customers. The Company believes it is essential to maintain the uptime of its critical network infrastructure for the benefit of its customers through the regular maintenance and replacement of its hardware in alignment with widely accepted technology best practices.

Further, this capital category represents the costs for new equipment for extensions of the IT infrastructure to meet the needs of our customers and an ever-changing and dangerous cyber landscape.

Q. Please provide detail regarding the annual capital spends represented on line 1 of Exhibit A-22 (NEK-14)?

A. As evidenced on line 1 of Exhibit A-22 (NEK-14), UPPCO's planned capital spending in this category in 2024 and 2025 is $181,426 and $592,176, respectively. The 2024 capital spending includes $45,000 for replacement of ruggedized computer tablets in the metering department, $5,000 for a replacement copier, $4,170 for laptops at the end of their planned life cycle, and $127,256 for end of life ("EOL") network hardware, primarily routers and switches. The 2025 capital spend amount of $592,176 includes $140,000 for copier and printer replacements at the end of their planned life cycle (five copiers, 16 printers), $179,400 for laptop and PC replacements at EOL (23 ruggedized laptops for line trucks, 38 laptops and 21 desktops), $250,000 for EOL network hardware, including security camara equipment, routers, switches, servers and other network infrastructure appliances.

Q. How will the capital spending represented on line 1 of Exhibit A-22 (NEK-14) benefit the customers of UPPCO?

A. Every utility relies upon its physical IT infrastructure (servers, routers, switches, firewall appliances, laptops, desktops, wiring) to provide the backbone on which the key applications required to serve their customers run. In the case of UPPCO, these essential applications include SCADA, SAP, Staking/Design, customer portal, and many others, without which, a utility would be unable to perform or deliver services and energy to customers. To maintain the reliability of that infrastructure, and therefore service to customers, all prudent companies employ a practice of scheduled replacement in order to maintain and replace equipment on a planned schedule to avoid emergency downtime. The Company believes it is essential to maintain the uptime of its critical network infrastructure for the benefit of its customers through the regular maintenance and replacement of its hardware in alignment with widely accepted technology best practices.

Q. How were the cost estimates presented on line 1 of Exhibit A-22 (NEK-14) derived?

A. Replacement of hardware infrastructure, when done properly, is a matter of routine purchasing of key equipment on a regular basis. As this is an activity of a frequent nature, current year pricing is informed through quoting of proposed purchases from previously qualified vendors. 2025 cost estimates are informed by 2024 quoted pricing indexed for inflation.

Q. Please explain the nature of the IT capital project on line 2 of Exhibit A-22 (NEK-14)?

A. Line No. 2 of Exhibit A-22 (NEK-14) represents UPPCO's required spending for long-term renewal of utility and business application software licensing. Licensing costs in excess of a 12-month term are required to be capitalized by accounting standards.

Q. Please explain why the capital spending on line 2 of Exhibit A-22 (NEK-14) is needed?

A. Without the licensing represented on line 2, the Company networks would cease to comply with contractual agreements with its software application suppliers and, in extreme circumstances, be forced into ceasing the use of software required for the daily operation of the utility.

Q. Please provide detail regarding the annual capital spends represented on line 2 of Exhibit A-22 (NEK-14)?

A. As evidenced on line 2 of Exhibit A-22 (NEK-14), UPPCO's planned capital spending in this category in 2024 and 2025 is $41,707 and $166,400, respectively. The 2024 capital spending of $41,707 if for a 3-year license for a hardware/software Documentation application. This software is utilized in tracking both physical and software applications present within the UPPCO network. The 2025 capital spend amount of $166,400 is for the 5-year renewal of UPPCO's Microsoft Data Center licensing for data center servers.

Q. How were the cost estimates presented on line 2 of Exhibit A-22 (NEK-14) derived?

A. Cost estimates for the 2024 capital spending for the hardware/software documentation application was quoted from an UPPCO pre-qualified software partner. The cost estimate for the Microsoft license renewal is derived from estimates received from UPPCO's Microsoft reseller and validated by internal staff based upon historical pricing.

Q. Please explain the nature of the IT capital project on Line No. 3 of Exhibit A-22 (NEK-14)?

A. Line No. 3 of Exhibit A-22 (NEK-14) represents the estimated cost of completion for consultative work required to complete a multi-year disaster recovery review and documentation of a new recommended DR plan.

Q. Please explain why the capital spending on line 3 of Exhibit A-22 (NEK-14) is needed?

A. Completion of the disaster recovery plan review and documentation of the Company's revised plan is needed in order to ensure a timely and effective recovery of operations in the event of a cyber or natural disaster event that causes the Company's operations to be suspended.

Q. Please provide detail regarding the annual capital spends represented on line 3 of Exhibit A-22 (NEK-14)?

A. As evidenced on line 3 of Exhibit A-22 (NEK-14), UPPCO's planned capital spending in this category in 2024 is $31,280.

Q. How will the capital spending represented on line 3 of Exhibit A-22 (NEK-14) benefit the customers of UPPCO?

A. A review and documentation of the disaster recovery plan will minimize interruption of services to customers in the event of a cyber or natural disaster event that results in an interruption of IT operations.

Q. How were the cost estimates presented on line 3 of Exhibit A-22 (NEK-14) derived?

A. Cost estimates for the 2024 capital spending are a result of obtaining quoted costs for consultants performing the work on UPPCO's disaster recovery plan.

Q. Please explain the nature of the IT capital project on line 4 of Exhibit A-22 (NEK-14)?

A. Line No. 4 of Exhibit A-22 (NEK-14) represents the cost of video equipment utilized for communicating between UPPCO facilities as well as with organizations outside of UPPCO. The use of video conferencing equipment enables clearer communication and improved understanding between parties brought about by face -to-face communication while eliminating the cost of travel and time for meeting participants.

Q. Please explain why the capital spending on line 4 of Exhibit A-22 (NEK-14) is needed?

A. While UPPCO is a relatively small organization by the standards of some other utilities in Michigan, the geographic footprint of the UPPCO service territory is immense, with eight service centers in two time zones spread across hundreds of miles. Video conferencing enables faster, more effective, and lower cost communication in order to better serve customers.

Q. Please provide detail regarding the annual capital spends represented on line 4 of Exhibit A-22 (NEK-14)?

A. As evidenced on line 4 of Exhibit A-22 (NEK-14), UPPCO's planned capital spending in this category in 2024 is $104,268. This equipment will be installed in the Community Room of the Ishpeming service center as part of our multi-year buildout of UPPCO's video conferencing capabilities. The Ishpeming Community Room is a large gathering space used for training, both safety and operational, as well as large company meeting such as quarterly town halls and leadership meetings.

Q. How will the capital spending represented on line 4 of Exhibit A-22 (NEK-14) benefit the customers of UPPCO?

A. While meetings are a fact of life in any organization, through the continued rollout of its video conferencing capabilities, UPPCO is working to minimize the time and cost of meetings while maximizing safety and operational training opportunities, all for the benefit of customers.

Q. How were the cost estimates presented on line 4 of Exhibit A-22 (NEK-14) derived?

A. Cost estimates for the 2024 capital spending are derived from quoted and historical costs as this is a multi-year rollout that began in 2020.

Q. Please explain the nature of the IT capital project on lines 5 and 6 of Exhibit A-22 (NEK-14)?

A. According to the 2023 IBM Security Cost of a Data Breach report, there were 3,205 data breaches in the United States in 2023, a 78% increase from the previous year and at an average cost of $4.45 million. The IT capital spending outlined in lines 5 and 6 of Exhibit A-22 (NEK-14) is for continuing investments to protect the IT network and applications of UPPCO, the data of our customers as well as protect access to the larger national grid. The Company has taken many critical steps to ensure these protections, including installation of cyber security applications across multiple entry points, required monthly cyber security training for all employees, random cyber intrusion testing, and implementation of multi-factor authentication. Despite the continued diligence of organizations like UPPCO to thwart the nefarious intentions of ever more aggressive threat actors, those threat actors continue to modify existing and create new tactics in an effort to infiltrate more organizations every day.

Q. Please explain why the capital spending on lines 5 and 6 of Exhibit A-22 (NEK-14) is needed?

A. All organizations, without continued investment to counter cyber threat actors are at increasing risk of data breaches, ransomware attacks and DDoS (Distributed Denial-of-Service) attacks. For an organization such as UPPCO, that could mean an exposure of customer data, a shutdown of energy distribution services, or opening a path for a larger attack upon critical regional or national energy infrastructure. Continued investment and attainment of knowledge and resources is required to minimize or negate innovative new threats.

Q. Please provide detail regarding the annual capital spends represented on lines 5 and 6 of Exhibit A-22 (NEK-14)?

A. As evidenced on line 5 of Exhibit A-22 (NEK-14), UPPCO's planned capital spending in this category in 2024 and 2025 is $356,365 and $395,200, respectively. The 2024 capital spending includes $83,414 for a Vulnerability Management and Security application designed to provide layered protection for Operational Technology systems such as SCADA, $41,707 for a DLP (data loss prevention) application, $62,561 for Cyber Arc for PAM (privileged access management), $65,000 to upgrade Microsoft licensing to E5 to gain enhanced security features, $61,977 to create a SEL Blue Frame Network to support OT access to power-grid relays, $20,853 for LastPass, an organizational password management application, and $20,853 for a TIP (threat intelligence platform) for dark web monitoring. The 2025 capital spending includes $104,000 for extensions to our cyber security applications and $291,200 for replacement of the Company's Cisco ASA network firewall which has reached end of life (Cisco has ended support for the appliance).

Q. How will the capital spending represented on lines 5 and 6 of Exhibit A-22 (NEK-14) benefit the customers of UPPCO?

A. UPPCO's continued investment in cyber security benefits customers by protecting their data and information from ever more aggressive threat actors, countering attempts to disrupt energy distribution services directly to the UPPCO footprint, as well as block larger attempts on regional and national infrastructure that would disrupt local service.

Q. How were the cost estimates presented on lines 5 and 6 of Exhibit A-22 (NEK-14) derived?

A. Cost estimates for the cyber security investments listed above are derived from estimates received from our software vendors. Products of this nature are largely “off the shelf” and costs are reflected in software company price sheets.

Q. Please explain the nature of the IT capital project on lines 7 and 8 of Exhibit A-22 (NEK-14)?

A. The IT capital spending outlined in lines 7 and 8 of Exhibit A-22 (NEK-14) represent the costs of environmental and functional upgrades to our ERP platform, SAP. This platform is utilized for customer and customer service management, inventory and work order management, and is UPPCO’s financial systems of record.

Q. Please explain why the capital spending on lines 7 and 8 of Exhibit A-22 (NEK-14) is needed?

A. UPPCO has currently invested over $20 million dollars in SAP, from its initial implementation in February of 2016 through and including 2023. ERP systems by their very nature require continual investment to ensure the reliability, security and functionality of the system is maintained. A significant portion of UPPCO’s 2024 capital spend for SAP ($886,278) is required due to the application developer (SAP) no longer supporting the version of the software the Company uses for its financial FERC conversion. In addition, additional enhancements, through upgrades and environmental changes bring advantages in the form of increased security and increased functionality or extensions in functionality, as is the case with UPPCO’s 2025 data warehouse project.

Q. Please provide detail regarding the annual capital spends represented on lines 7 and 8 of Exhibit A-22 (NEK-14)?

A. As evidenced on lines 7 and 8 of Exhibit A-22 (NEK-14), UPPCO's planned capital spending in this category in 2024 and 2025 is $1,055,460 and $832,000, respectively. The 2024 capital spending includes $1,003,426 to upgrade the expiring version (EOL) for UPPCO's FERC translation module in SAP Hana and $52,134 for configuration upgrades for regulatory needs. The 2025 capital spending includes $520,000 for implementation of a SAP data warehouse and $312,000 for SAP version upgrades to address SAP modules scheduled for vendor end of support.

Q. What benefits will the capital spending represented on lines 7 and 8 of Exhibit A-22 (NEK-14) provide?

A. UPPCO's ERP platform is a foundational element of the utility, without which the Company could not continue to perform most of the key functions of an electric utility. The continued investment in SAP benefits customers by ensuing the system is available for reliable and accurate billing, assisting in the response to all customer queries, and ensuring the availability of needed equipment and supplies required in the daily operations of the utility. Further, as the system of financial record for UPPCO, it is vital to the accurate reporting of results to governmental regulators. UPPCO also seeks to better leverage the significant data in SAP through its 2025 data warehouse project for purposes of better predicting customer and operational needs to continually improve customer service and operational performance.

Q. How were the cost estimates presented on lines 7 and 8 of Exhibit A-22 (NEK-14) derived?

A. Cost estimates for the ERP related projects are derived through pricing indications directly from SAP and our third-party ERP consultant, Utegration.

Q. Please explain the nature of the IT capital project on lines 9 and 10 of Exhibit A-22 (NEK-14)?

A. The IT capital spending outlined in lines 9 and 10 of Exhibit A-22 (NEK-14) represent the costs for maintaining and upgrading UPPCO's Advanced Metering Infrastructure ("AMI") network. The costs in this category include equipment (hardware) essential to the AMI communications network (CGRs) and application software required for the collection and translation of usage data for billing and operational reporting and functionality (Itron Enterprise Edition "IEE").

Q. Please explain why the capital spending on lines 9 and 10 of Exhibit A-22 (NEK-14) is needed?

A. The current version of UPPCO's AMI data collection and translation application, IEE Version 9.0 has reached its end of support life from the application developer, Itron. While Itron has agreed to extend support through 2024, as UPPCO upgrades to its updated supported version of IEE, after 2024 Itron will no longer be updating security and operational patching for the application, rendering the Company at risk of customer data breaches and increased downtime for reporting and billing unless we upgrade to the latest edition.

The CGR hardware utilized in the communications network of AMI are also at end of life. These individual pieces of equipment that form the backbone of the AMI communications relay network have a defined useful life of five years and were originally issued in 2019. While this equipment will unlikely fail all at once, individual nodes will begin to fail over time and due to the mesh nature of the AMI communications network, individual failures will begin to cascade into decreased reliability of the AMI system's ability to read and communicate customer usage data, resulting in significant delays in billing to customers and availability of information for operational use.

Q. Please provide detail regarding the annual capital spends represented on lines 9 and 10 of Exhibit A-22 (NEK-14)?

A. As evidenced on lines 9 and 10 of Exhibit A-22 (NEK-14), UPPCO's planned capital spending in this category in 2024 and 2025 is $1,582,788 and $1,820,000, respectively. The 2024 capital spending includes $1,564,020 update to a supported version of the application software IEE and $18,768 for the replacement of failed CGR nodes. The 2025 capital spending includes $1,820,000 for the replacement of the AMI end of life CGR fleet.

Q. What benefits will the capital spending represented on lines 9 and 10 of Exhibit A-22 (NEK-14) provide?

A. The UPPCO AMI system ensures timely reporting and billing of customer usage data. The CGR network is the physical backbone of that network, without which, the system will not perform. IEE is the application software required to collect and translate the usage data into usable information, and again, without which, the system cannot perform properly. Without a reliable AMI network and application layer, UPPCO would instead need to revert to manual reading of customer meter data, resulting in a significant increase in operational costs and a likely return to usage estimation for periodic customer billing.

Q. How were the cost estimates presented on lines 9 and 10 of Exhibit A-22 (NEK-14) derived?

A. Cost estimates for the IEE application update were derived after completion of the project scope of work (SOW) in conjunction with Itron and estimates of for internal staffing required on the project as well as consultative hours required of the vendor.

CGR costs were derived using quotes from our equipment supplier and an estimate of internal labor required for installation as tracked from the original installation in 2019 and 2020.

Q. Please explain the nature of the IT capital project on line 11 of Exhibit A-22 (NEK-14)?

A. The IT capital spending outlined on line 11 of Exhibit A-22 (NEK-14) represent the costs of improvements in our customer service operations. Most significantly, UPPCO will be able to implement proactive messaging to customers outside of billing statements through consented push notifications for outages, planned outages, service appointments as well as billing and payment information. The proposed applications will allow for multiple communications methods, including email, text, and voice alerts.

Q. Please explain why the capital spending on line 11 of Exhibit A-22 (NEK-14) is needed?

A. The customer service projects included in line 11 of Exhibit A-22 (NEK-14) are needed for improved communications between UPPCO and our customers. The projects will enable targeted, proactive outbound and two-way communication to keep customers informed of utility operations and billing issues that will impact the customers directly.

Q. Please provide detail regarding the annual capital spends represented on line 11 of Exhibit A-22 (NEK-14)?

A. As evidenced on line 11 of Exhibit A-22 (NEK-14), UPPCO's planned capital spending in this category in 2024 is $307,590. The 2024 capital spending is for implementation of a customer alerting and notification application (My HQ).

Q. What benefits will the capital spending represented on line 11 of Exhibit A-22 (NEK-14) provide?

A. All of the projects contemplated for UPPCO's customer service operation are intended to improve communication with customers. These projects will enable more timely and proactive alerting of events or circumstances that directly affect customers, in some cases for awareness and in others so that customers are better able to take informed actions as necessary. Each project will enable improved engagement between customers and UPPCO.

Q. How were the cost estimates presented on line 11 of Exhibit A-22 (NEK-14) derived?

A. The projects in the customer service category on line 11 of the exhibit will be completed in consultation with our long-time, third-party customer service partner Kubra. The cost estimates for these projects were provided by Kubra and include estimates of additional costs associated with interfaces required to be completed by a second SAP partner, Utegration.

Q. Please explain the nature of the IT capital project on lines 12 through 15 of Exhibit A-22 (NEK-14)?

A. The spending outlined in lines 12 through 15 of Exhibit A-22 (NEK-14) represent the costs for IT projects within our Operational Technologies (OT) functionalities. Each of these projects is specific to a functionality or applications utilized in the operations of the utility including the Systems Operating Center ("SOC"), Designing, Locating (GIS), SCADA operations and distribution line clearing.

Q. Please explain why the capital spending on lines 12 through 15 of Exhibit A-22 (NEK-14) are needed?

A. The IT capital spending outlined on lines 12 through 15 of Exhibit A-22 (NEK-14) represent the costs of improvements to support operations and grid accuracy through maintaining, designing, and documenting our electrical infrastructure.

a. The SOC Upgrade - Line 12: Represents cost for an updated and upgraded SOC video monitoring system. The current system is two years beyond its OEM support life and is currently experiencing intermittent downtime inhibiting the proper monitoring of UPPCO's grid operations.

b. The Staking/Design Tool - Line 13: Represents the cost for replacement of UPPCO's design application. There is significant risk of failure with the current, obsolete design tool implemented in 2016 due to limited available support from the original developer. The selected design application from GeoDigital is a utility industry standard and will support enhanced capabilities, including GPS coordinates captures integral to the design and additional engineer calculations to support NESC design criteria.

c. GIS (ESIR) Enhancements - Line 14: Represents an update in version to the Company's current GIS (ESRI) application. The current version reaches EOL and end of support on March 1, 2026.

d. Aerial Line Clearing Application - Line 15: This application enhancement will support direct integration with the Company's GIS system to more effectively identify areas of need and more efficiently schedule line clearance work, resulting a more efficient use of operating expense dollars and reduced outages.

Q. Please provide detail regarding the annual capital spends represented on lines 12 through 15 of Exhibit A-22 (NEK-14)?

A. As evidenced on lines 12 through 15 of Exhibit A-22 (NEK-14), UPPCO's planned capital spending in this category in 2024 and 2025 is $896,705 and $384,800, respectively. The 2024 capital spending includes $521,340 for upgraded equipment in the SOC and $375,365 for implementation of a new design application started in 2023 and going live in 2024 with final enhancements being implemented in 2025. The 2025 capital spending includes $124,800 for completion of the design tool enhancements, $104,000 for the new release of UPPCO's GIS application, and $156,000 to implement a new aerial line clearing application.

Q. What benefits will the capital spending represented on lines 12 through 15 of Exhibit A-22 (NEK-14) provide?

The benefit of UPPCO's proposed investments in the design tool and GIS application is to maintain and improve the accuracy of the documentation of the Company's electrical grid. This requires that a prudent organization maintain up-to-date and vendor supported releases of software applications, especially in critical functions such as engineering and design. Doing so ensures the accuracy of data to support reliability, efficiency, and customer service. These systems interface directly with the Company's OMS and SCADA to ensure efficient emergent response to better serve our customers.

In addition, integrating the aerial line clearing application into UPPCO's distribution operations will ensure the Company can deploy line clearance where is it is most efficient to minimize outage and reduce cost.

The SOC video monitoring replacement and upgrade will allow monitoring of our Hydro facilities and electrical grid and is critical to ensure the safety and reliability of our systems for the benefit of UPPCO's customers.

Q. How were the cost estimates presented on lines 12 through 15 of Exhibit A-22 (NEK-14) derived?

The project cost estimates for Lines 12 through 15 were derived from direct quotes or like requests from the Company's established software venders. Where direct quote was not possible, UPPCO estimated costs based upon discussions with other utilities that have completed similar implementations.

Q. Please explain the nature of the IT capital project on line 16 of Exhibit A-22 (NEK-14)?

B. Line No. 16 of Exhibit A-22 (NEK-14) represents the cost of projects that are safety and training related, including implementation of a new learning management system (LMS), upgrades to radio identifications software and driver safety training applications. Our belief at UPPCO is that sound safety operations leads directly to reliable and safe service and we remain committed to providing a safe place to work for employees and a safe environment for our customers. Proper training of safety methods is the beginning of that process.

Q. Please explain why the capital spending on line 16 of Exhibit A-22 (NEK-14) is needed?

A. Each of the projects in this category is rooted in safety and continuous improvement in safety performance is the justification for each. The radio identification enhancements will better enable tracking of field employees for safety purposes as UPPCO's service territory is spread out and often requires employees to be in unpopulated areas. The ability to know where our employees are in the event of an emergency is vital to that employee's safety.

UPPCO will also be replacing its LMS delivery system in 2024. The new system will streamline deliver of training to employees and track progress toward learning goals. While this system is oriented toward safety programs, it will include learning modules for all employees, both field and administrative.

Q. Please provide detail regarding the annual capital spends represented on line 16 of Exhibit A-22 (NEK-14)?

B. As evidenced on line 16 of Exhibit A-22 (NEK-14), UPPCO's planned capital spending in this category in 2024 is $94,884. The 2024 capital spending includes $20,854 for radio identification software, $26,067 for driver qualification software, and $47,963 for a new LMS application.

Q. Does this conclude your direct testimony?

A. Yes

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
***

In the matter of the application of	)	
UPPER PENINSULA POWER COMPANY	)	
for authority to increase its rates for the generation	)	Case No. U-21555
and distribution of electricity and other relief.	)	
	)	

DIRECT TESTIMONY AND EXHIBITS OF

JOHN S. THOMPSON

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

March 21, 2024

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GLOSSARY

Algonquin	Algonquin Power & Utilities Corp.
CAPM	Capital Asset Pricing Model
Commission	Michigan Public Service Commission
CPI	Consumer Price Index
DCF	Discounted Cash Flow
DPS	Dividends Per Share
ECAPM	Empirical Capital Asset Pricing Model
EPS	Earnings Per Share
FERC	Federal Energy Regulatory Commission
FINCAP, Inc.	Financial Concepts and Applications, Inc.
FOMC	Federal Open Market Committee
GDP	Gross Domestic Product
IBES	Institutional Brokers' Estimate System (now Refinitiv)
Moody's	Moody's Investors Service
MW	Megawatts
NASDAQ	The Nasdaq Stock Market LLC
NYSE	New York Stock Exchange
PCE	Personal Consumption Expenditure Price Index
ROE	Return On Equity
RRA	S&P Global Market Intelligence, RRA Regulatory Focus (formerly Regulatory Research Associates, Inc.
S&P	S&P Global Ratings
UPPCO or Company	Upper Peninsula Power Company
Value Line	The Value Line Investment Survey
Zacks	Zacks Investment Research, Inc.

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. John S. Thompson, 3907 Red River, Austin, Texas, 78751.

Q2. IN WHAT CAPACITY ARE YOU EMPLOYED?

A2. I am an independent consultant in regulatory finance and economics. I am affiliated with FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND QUALIFICATIONS.

A3. A description of my background and qualifications, including a resume containing the details of my experience, is attached as A-43 (JST-1).

Q4. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS CASE?

A4. The purpose of my direct testimony is to present to the Commission my independent assessment of the just and reasonable ROE that UPPCO should be authorized to earn on its investment in providing electric utility service. In addition, I also examine the reasonableness of UPPCO's requested capital structure, considering both the specific risks faced by the Company and other industry guidelines.

Q5. PLEASE SUMMARIZE THE INFORMATION AND MATERIALS YOU RELY ON TO SUPPORT THE OPINIONS AND CONCLUSIONS CONTAINED IN YOUR TESTIMONY.

A5. To prepare my testimony, I use information from a variety of sources that would normally be relied upon by a person in my capacity. In connection with the present filing, I consider and rely upon discussions with corporate management, publicly available financial reports, and prior regulatory filings relating to UPPCO. I also review information relating generally to current capital market conditions and specifically to investor perceptions, requirements, and expectations for UPPCO's utility operations.

These sources, coupled with my experience in the fields of economics, finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for UPPCO, and they form the basis of my analyses and conclusions.

Q6. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A6. Yes. I am sponsoring the following Exhibits, which were prepared by me:

Exhibit	**Description**
A-43 (JST-1)	Qualifications of John S. Thompson
A-44 (JST-2)	Summary of Results
A-45 (JST-3)	Regulatory Mechanisms – Utility Group
A-46 (JST-4)	DCF Model – Utility Group
A-47 (JST-5)	BR + SV Growth Rate – Utility Group
A-48 (JST-6)	CAPM Model – Utility Group
A-49 (JST-7)	Utility Risk Premium
A-50 (JST-8)	Expected Earnings Benchmark – Utility Group
A-51 (JST-9)	DCF Model – Non-Utility Group
A-52 (JST-10)	Capital Structure

Q7. HOW IS YOUR TESTIMONY ORGANIZED?

A7. After discussing important economic and legal foundations that are relevant to my analyses, I summarize my findings and conclusions. I then briefly review UPPCO's operations and finances. I then explain the development of the proxy group of electric utilities that I use as the basis for my quantitative analyses, followed by an evaluation of UPPCO's relative risks. Next, I discuss current conditions in the capital markets and their implications in evaluating a just and reasonable return for the Company. With this as a background, I discuss well-accepted quantitative analyses to estimate the current cost of equity for the proxy group of utilities. These include the DCF model, the CAPM, and an equity risk premium approach based on allowed equity returns, which are all methods that are commonly relied on in regulatory proceedings. I then discuss

UPPCO's requested ROE in the context of my findings, and I conclude that the 10.7% ROE requested by UPPCO is conservative. This determination takes into account the specific risks for the Company's utility operations in Michigan and its requirements for financial strength. I then corroborate the results of my utility quantitative analyses with reference to an expected earnings benchmark. Further, consistent with the fact that utilities must compete for capital with firms outside their own industry, I apply the DCF model to a group of low-risk non-utility firms, which serves as an additional benchmark. My testimony concludes with a discussion of capital structure.

II. ECONOMIC PRINCIPLES AND REGULATORY STANDARDS

Q8. WHAT IS THE PURPOSE OF THIS SECTION?

A8. This section outlines and discusses the economic principles and regulatory standards that underpin my analyses and the conclusions I reach in my testimony. This section also discusses some of the challenges and practical considerations in determining a just and reasonable ROE for regulated utilities.

A. Economic Principles

Q9. WHAT IS ROE, AND HOW DOES IT RELATE TO UTILITIES?

A9. The ROE is the cost to a firm of attracting and retaining common equity investment in that firm. Like most firms, utilities require common equity investment in order to partially finance their assets.[1] This investment is necessary to finance the asset base the utility requires in order to provide utility service. A given utility competes with other firms for equity capital in capital markets, and these firms make up the demand side of these markets. Investors commit capital in capital markets only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks, and such investors make up the supply side of these

[1] It is also common for firms to partially finance their assets through debt. Utilities are no exception, as almost all utilities finance their assets through a blend of various debt and equity sources.

markets. In well-functioning capital markets, the ROE is akin to a market clearing price, as it ensures that the supply of equity capital is equal to the demand, and that there is no surplus or shortage of equity capital.

Q10. PLEASE CHARACTERIZE THE COST STRUCTURE OF A TYPICAL UTILITY.

A10. Utilities are generally characterized by very high fixed costs coming from an installed base of assets such as the hydro generation facilities and distribution lines UPPCO uses to transport electricity from points of interconnections with upstream suppliers to the utility's customers. Compared to these high fixed costs, utilities' marginal costs tend to be relatively low.[2] In standard economic theory, high fixed costs coupled with low marginal costs creates "economies of scale" in which the average cost to a firm tends to fall over a large range of output. If the average cost falls over the entire output that the market demands, monopolies will naturally form because it will always be more efficient for a single firm to serve the entire market as compared to two or more firms. If they are not regulated, such "natural monopolies" would tend to price their output significantly higher than what would occur in an otherwise competitive market, creating monopoly profits for the natural monopoly and a "deadweight" efficiency loss for the market as a whole.

Q11. GENERALLY SPEAKING, HOW ARE UTILITIES REGULATED?

A11. Utilities are regulated such that they ultimately are required to price their utility service based on their cost of service, earning a return that is competitive with other similar risk enterprises. Because direct price regulation is unfeasible, utility regulation allows for a "just and reasonable" (i.e., competitive) ROE to attract capital for utility investment. Under accepted regulatory standards, utilities are allowed to price their utility service

[2] The utilities' marginal costs are their per-unit cost of delivering electricity or natural gas to their customers.

such that they recover the cost to serve their customers and have the opportunity to earn competitive ROEs, allowing for differences in risk.

Q12. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THE COST OF EQUITY CONCEPT?

A12. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets in capital markets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return, and

RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q13. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN CAPITAL MARKETS?

A13. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. Comparing the observed yields on government securities, which are considered free of default risk, to the yields on bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

Q14. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A14. It is widely accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets, including common stock, the required rates of return cannot be directly observed. Yet, there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q15. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A15. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. As noted earlier, long-term debt is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. The last investors in line are common shareholders: they receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

B. Regulatory Standards

Q16. WHAT IS THE FOUNDATION FOR A JUST AND REASONABLE ROE?

A16. A just and reasonable ROE is integral in meeting sound regulatory economics and the standards set forth by the U.S. Supreme Court in two landmark cases, *Bluefield* and

Hope. The *Bluefield* case set the standard against which just and reasonable rates are measured:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties…. The return should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties.[3]

The *Hope* case expanded on the guidelines as to a reasonable ROE, reemphasizing the findings in *Bluefield* and establishing that the rate-setting process must produce an end-result that allows the utility a reasonable opportunity to cover its capital costs. The Court stated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock…. By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain credit and attract capital.[4]

In summary, the Supreme Court's findings in *Bluefield* and *Hope* established that a just and reasonable ROE must be sufficient to 1) fairly compensate the utility's investors, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. These standards should allow the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system replacement and expansion, but the

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[3] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[4] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

Supreme Court's requirements can only be met if the utility has a reasonable opportunity to actually earn its allowed ROE.

Q17. HOW DOES A UTILITY'S AUTHORIZED ROE HELP TO MAINTAIN REGULATORY STANDARDS?

A17. The authorized ROE acts like a price signal in capital markets, and it informs investors about the return they may receive if they allocate equity capital to a particular investment, allowing them to make informed judgements about how best to allocate their capital. Investors will commit money to a particular investment only if they expect it to produce a return at least commensurate with those from other investments with comparable risks. To maintain regulatory standards, the ROE must be sufficient to compensate common equity investors for the use of their capital and support the utility's financial integrity and ongoing ability to finance the plant and equipment necessary to provide utility service.

Q18. IS IT WIDELY ACCEPTED THAT A UTILITY'S ABILITY TO ATTRACT CAPITAL MUST BE CONSIDERED IN ESTABLISHING A FAIR RATE OF RETURN?

A18. Yes. This is a fundamental standard underlying the regulation of public utilities. The Supreme Court's *Bluefield* and *Hope* decisions established that a regulated utility's authorized returns on capital must be sufficient to assure investors' confidence and that, if the utility is efficient and prudent on a prospective basis, it will be able to maintain and support its credit and have the opportunity to raise necessary capital.[5]

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[5] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) ("Bluefield"); *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("Hope").

C. Practical Considerations

Q19. WHAT ARE THE CHALLENGES IN DETERMINING A JUST AND REASONABLE ROE FOR A REGULATED ENTERPRISE?

A19. The actual return investors require is unobservable. Different methodologies have been developed to estimate investors' expected and required return on capital, but all such methodologies are merely theoretical tools and generally produce a range of estimates, based on different assumptions and inputs. The DCF method, which is frequently referenced and relied on by regulators at least in part, is only one theoretical approach to gain insight into the return investors require; there are numerous other methodologies for estimating the cost of capital and the ranges produced by the different approaches can vary widely.

Q20. DO *BLUEFIELD* AND *HOPE* REQUIRE A PARTICULAR METHOD TO BE FOLLOWED IN ORDER TO ESTABLISH A JUST AND REASONABLE ROE?

A20. No. While the *Bluefield* and *Hope* decisions did not establish a particular method to be followed in determining the allowed ROE (or in fixing rates),[6] these and subsequent cases enshrined the importance of an end result that meets the opportunity cost standard of finance. Under this doctrine, the required return is established by investors in the capital markets based on expected returns available from other comparable risk investments. Coupled with modern financial theory, which has led to the development of formal risk-return models (e.g., DCF and CAPM), practical application of the *Bluefield* and *Hope* standards involves the independent, case-by-case consideration of a firm's risk along with current capital market data in order to evaluate a ROE that will produce a balanced and fair end result for investors and customers.

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[6] *Id.* at 602 (finding, "the Commission was not bound to the use of any single formula or combination of formulae in determining rates." and, "[I]t is not theory but the impact of the rate order which counts.")

Q21. IS IT CUSTOMARY TO CONSIDER THE RESULTS OF MULTIPLE APPROACHES WHEN EVALUATING A JUST AND REASONABLE ROE?

A21. Yes. In my experience, financial analysts and regulators routinely consider the results of alternative approaches in determining allowed ROEs. It is widely recognized that no single method can be regarded as failsafe; with all approaches having advantages and shortcomings. As FERC has noted, "[t]he determination of rate of return on equity starts from the premise that there is no single approach or methodology for determining the correct rate of return."[7] Similarly, a publication of the Society of Utility and Regulatory Financial Analysts concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[8]

As this treatise succinctly observed, "no single model is so inherently precise that it can be relied on solely to the exclusion of other theoretically sound models."[9] Similarly, *New Regulatory Finance* concluded that:

> There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology possesses its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises that cannot be validated empirically. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. There is no monopoly as to which method is used by investors.

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[7] *Northwest Pipeline Co.*, Opinion No. 396-C, 81 FERC ¶ 61,036 at 4 (1997).

[8] David C. Parcell, *The Cost of Capital – A Practitioner's Guide*, Society of Utility and Regulatory Financial Analysts (2010) at 84.

[9] *Id.*

> In the absence of any hard evidence as to which method outdoes the other, all relevant evidence should be used and weighted equally, in order to minimize judgmental error, measurement error, and conceptual infirmities.[10]

Thus, while the DCF model is a recognized approach to estimating the ROE, it is not without shortcomings and does not otherwise eliminate the need to ensure that the "end result" is fair. The Indiana Utility Regulatory Commission has also recognized this principle:

> There are three principal reasons for our unwillingness to place a great deal of weight on the results of any DCF analysis. One is. . . the failure of the DCF model to conform to reality. The second is the undeniable fact that rarely if ever do two expert witnesses agree on the terms of a DCF equation for the same utility – for example, as we shall see in more detail below, projections of future dividend cash flow and anticipated price appreciation of the stock can vary widely. And, the third reason is that the unadjusted DCF result is almost always well below what any informed financial analysis would regard as defensible, and therefore require an upward adjustment based largely on the expert witness's judgment. In these circumstances, we find it difficult to regard the results of a DCF computation as any more than suggestive.[11]

More recently, FERC recognized the potential for any application of the DCF model to produce unreliable results.[12] The Maryland Public Service Commission echoed this sentiment in a recent rate case, stating "We have repeatedly stated that we are unwilling to rule that there can be only one correct method for calculating ROE."[13]

As this discussion indicates, consideration of the results of alternative approaches reduces the potential for error associated with any single quantitative method. Just as investors inform their decisions using a variety of methodologies, my evaluation of a fair ROE for the Company considered the results of multiple financial models.

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[10] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 429.
[11] *Ind. Michigan Power Co.*, Cause No. 38728, 116 PUR4th, 1, 17-18 (IURC 8/24/1990).
[12] *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234 at P 41 (2014).
[13] Maryland Public Service Commission Order 88033, Case No. 9424 (ML No. 16 212676).

Q22. HOW DO YOU APPROACH THE TASK OF EVALUATING A JUST AND REASONABLE ROE FOR UPPCO IN THE CONTEXT OF *BLUEFIELD* AND *HOPE*?

A22. The goal is to generate the best estimate of UPPCO's ROE in today's capital markets. My testimony presents an analysis of investors' expectations and requirements using commonly referenced and theoretically sound financial models, reasonable assumptions about rational investor behavior, and data inputs that are consistent with the assumptions underlying financial models that I utilize, all within a consideration of broader capital market conditions and recent economic trends. Each of the approaches I use to estimate UPPCO's ROE has their own strengths and weaknesses, and all involve some degree of judgment. None of the models I use are inherently superior to any of the other models, and all of them are accepted methodologies for estimating the cost of equity in today's capital markets.

III. RETURN ON EQUITY FOR UPPCO

Q23. WHAT IS THE PURPOSE OF THIS SECTION?

A23. This section summarizes the findings supporting my conclusion that the 10.7% ROE requested for UPPCO's electric utility operations is a conservative estimate of investors' required rate of return for the Company. This section also discusses the relationship between the ROE and preservation of a utility's financial integrity and the ability to attract capital.

A. Importance of Financial Strength

Q24. THROUGHOUT YOUR TESTIMONY YOU REFER REPEATEDLY TO THE CONCEPTS OF "FINANCIAL STRENGTH," "FINANCIAL INTEGRITY,"

AND "FINANCIAL FLEXIBILITY." WOULD YOU BRIEFLY DESCRIBE WHAT YOU MEAN BY THESE TERMS?

A24. These terms are generally synonymous and refer to the utility's ability to attract and retain the capital that is necessary to provide service at reasonable cost, consistent with the U.S. Supreme Court standards. UPPCO continues to make capital investments to preserve and enhance service reliability for its customers. The Company must generate adequate cash flow from operations to fund these requirements and for repayment of maturing debt, together with access to capital from external sources under reasonable terms, on a sustainable basis.

Rating agencies and potential debt investors tend to place significant emphasis on maintaining strong financial metrics and credit ratings that support access to debt capital markets under reasonable terms. This emphasis on financial metrics and credit ratings is shared by equity investors who also focus on cash flows, capital structure and liquidity, much like debt investors. Investors understand the important role that a supportive regulatory environment plays in establishing a sound financial profile that will permit the utility access to debt and equity capital markets on reasonable terms in both favorable financial markets and during times of potential disruption and crisis.

Q25. WHAT PART DOES REGULATION PLAY IN ENSURING THAT UPPCO HAS ACCESS TO CAPITAL UNDER REASONABLE TERMS AND ON A SUSTAINABLE BASIS?

A25. Regulatory signals are a major driver of investors' risk assessment for utilities. Investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity. Security analysts study commission orders and regulatory policy statements to advise investors about where to put their money. As Moody's noted, "the regulatory environment is the most important driver of our outlook because it sets the pace for cost recovery."[14] Similarly, S&P observed that, "Regulatory advantage is the most heavily weighted factor when S&P Global Ratings analyzes a regulated utility's business risk profile."[15] More recently, S&P confirmed that "Utility regulation, no matter where on the continuum of our assessments, strengthens a utility's business risk profile, and generally underpins our ratings."[16] The Value Line Investment Survey ("Value Line") summarizes these sentiments:

> As we often point out, the most important factor in any utility's success, whether it provides electricity, gas, or water, is the regulatory climate in which it operates. Harsh regulatory conditions can make it nearly impossible for the best run utilities to earn a reasonable return on their investment.[17]

In addition, the ROE set by regulators impacts investor confidence in the jurisdictional utility, which ultimately impacts its ability to raise common equity capital from investors.

Q26. DO CUSTOMERS BENEFIT WHEN A UTILITY'S FINANCIAL FLEXIBILITY IS ENHANCED?

A26. Yes. Providing a ROE that is sufficient to maintain UPPCO's ability to attract capital under reasonable terms, even in times of financial and market stress, is not only consistent with the economic requirements embodied in the U.S. Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. Regulatory policies that support the utility's financial strength ultimately benefit customers through lower

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[14] Moody's Investors Service, *Regulation Will Keep Cash Flow Stable As Major Tax Break Ends*, Industry Outlook (Feb. 19, 2014).

[15] S&P Global Ratings, *Assessing U.S. Investors-Owned Utility Regulatory Environments*, RatingsExpress (Aug. 10, 2016).

[16] S&P Global Ratings, *North American Utility Regulatory Jurisdictions: Some Notable Developments* (Nov. 10, 2023).

[17] Value Line Investment Survey, *Water Utility Industry* (Jan. 13, 2017) at p. 1780.

interest rates on debt securities and by maintaining the liquidity required to ensure safe and reliable service.

B. Conclusions and Recommendations

Q27. WHAT ARE YOUR FINDINGS REGARDING THE FAIR ROE FOR UPPCO?

A27. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital under reasonable terms, I determined that 10.7% is a conservative estimate of investors' required ROE for UPPCO.

Q28. HOW DID YOU REACH THAT CONCLUSION?

A28. In estimating a fair ROE for UPPCO, my analyses focused on a proxy group of 23 publicly traded electric utilities. As discussed in my testimony:

- In order to reflect the risks and prospects associated with UPPCO's jurisdictional utility operations, my analyses begin by focusing on a proxy group of firms in Value Line's "Electric Utility" industry.
- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied the DCF, CAPM and risk premium methods to estimate a just and reasonable ROE, as well as referencing the expected earnings approach.
- Current capital market conditions highlight the imperative of considering alternatives to the DCF model.
- Based on the results of these analyses, and giving less weight to extremes at the high and low ends of the range, I conclude that the cost of equity for the large, publicly traded electric utilities in the proxy group fall in the 10.4% to 11.4% range.
- This conclusion is supported by reference to the expected earnings of my proxy group companies and to the average DCF estimates for a low-risk group of firms in the competitive sector of the economy.[18]
- An ROE at the high end of my recommended range is warranted for UPPCO because of the additional uncertainties associated with the Company's relatively small size, limited service territory, and relative lack of adjustment mechanisms. Based on the results outlined above, I conclude that the 10.7%

[18] As discussed in my testimony, these non-utility companies, which include household names such as Coca-Cola, McDonalds, Proctor & Gamble, and Walmart, have long corporate histories, well-established track records, and an overall risk profile that is more conservative than UPPCO or the electric utilities in the proxy group.

ROE requested by the Company represents a conservative estimate of investors' requirements.

Q29. WHAT DID YOUR EXPECTED EARNINGS BENCHMARK AND THE DCF RESULTS FOR YOUR SELECT GROUP OF NON-UTILITY FIRMS INDICATE WITH RESPECT TO YOUR EVALUATION?

A29. An expected earnings analysis for the proxy group of electric utilities yields a 10.8% ROE. Meanwhile, average DCF estimates for a low-risk group of firms in the competitive sector of the economy ranged from 10.4% to 10.7%. A summary of the DCF method results is shown in Exhibit A-44 (JST-2). Considering the clear risk differences between UPPCO and this low-risk group of firms in the competitive sector, these results confirm that a 10.7% ROE for UPPCO is within a reasonable range.

Q30. WHAT IS YOUR CONCLUSION AS TO THE REASONABLENESS OF UPPCO'S CAPITAL STRUCTURE?

A30. Based on my evaluation, I conclude that UPPCO's capital structure, consisting of approximately 51.5% common equity financing, represents a reasonable basis on which to establish the Company's return.

IV. FUNDAMENTAL ANALYSES

Q31. WHAT IS THE PURPOSE OF THIS SECTION?

A31. My objective is to evaluate and recommend a fair and reasonable ROE for UPPCO. Much of my work is predicated on a comparison of the Company with the utility industry, and more specifically to a proxy group of publicly traded utilities included in Value Line's "Electric Utility" industry group. As a foundation for my opinions and subsequent quantitative analyses, this section briefly reviews the operations and finances of UPPCO. In addition, I explain the basis for the proxy group I use to estimate the cost of equity and compare the investment risks of UPPCO with my reference group. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of the ROE.

A. UPPCO

Q32. BRIEFLY DESCRIBE UPPCO AND ITS MICHIGAN UTILITY OPERATIONS.

A32. UPPCO's regulated utility operations encompass the electric generation, transmission and distribution functions. Originally formed in 1947, UPPCO provides service to approximately 53,300 retail electric customers consisting of residential, commercial, industrial, and government entities. Industrial customers represent a significant portion of the Company's sales, and these large customers accounted for 22.3% of UPPCO's total revenues from electricity sales in 2022.[19] The Company's service territory covers ten counties constituting most of Michigan's Upper Peninsula, where UPPCO is the largest electricity provider. UPPCO's generation and distribution assets include 3,300 miles of distribution line, 58 substations and 80 MW of generating capacity. UPPCO's power requirements are met primarily through wholesale purchases, with the remainder being supplied from seven company-owned hydroelectric generating facilities and one 50-year-old combustion turbine.

During 2022, UPPCO's total kilowatt hour sales distribution consisted of 33.3% residential, 18.0% commercial, 43.8% industrial, and 4.8% governmental and sales for resale.[20] The large proportion of energy sales attributable to industrial customers relates to the significant paper production and forest products industries located in UPPCO's service area. The Company's 2022 peak load of 167 MW occurred on February 16.[21] UPPCO's energy supply mix consists primarily of hydro (14.9%) and purchased energy

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[19] FERC Financial Report, FERC Form No. 1, *Upper Peninsula Power Company* (Apr. 19, 2023).

[20] UPPCO 2022 FERC Form 1 at 300-301. In 2022, UPPCO's total electric sales revenue consisted of 49.1% residential, 21.1% commercial, 22.3% industrial, 3.3% governmental and sales for resale.

[21] *Id.* at 401b.

(85.1%) sources.[22] UPPCO's total 2022 operating revenues were approximately $116.6 million and total assets at year-end 2022 were $399.8 million.[23]

Q33. WHERE DOES UPPCO OBTAIN THE CAPITAL USED TO FINANCE ITS INVESTMENT IN UTILITY PLANT?

A33. As a wholly-owned subsidiary, UPPCO's common equity capital is provided by Axium UP Holdings, LLC. Axium is an affiliate of Axium Infrastructure, a portfolio investment firm that invests in infrastructure assets. As of September 30, 2022, Axium Infrastructure had more than $6.0 billion in assets under management and $1.4 billion in co-investments.

Q34. DOES UPPCO ANTICIPATE THE NEED FOR ADDITIONAL CAPITAL IN THE FUTURE?

A34. Yes. The Company must undertake investments to meet growing peak demand needs and provide for necessary maintenance and replacements of its utility systems as it continues to provide safe and reliable service to its customers. Continued support for UPPCO's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

B. Electric Utility Group

Q35. HOW DO YOU IMPLEMENT QUANTITATIVE METHODS TO ESTIMATE THE COST OF COMMON EQUITY FOR UPPCO?

A35. Application of quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices and beta values. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate of investors' expected return. Thus, the accepted approach to increase

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22 *Id.* at 401a.

23 *Id.* at 114 and 111.

confidence in the results is to apply quantitative methods to a proxy group of publicly traded companies that investors regard as risk comparable. While the proxy group provides a starting point in evaluating the cost of equity for UPPCO, as noted earlier, economic and regulatory standards require that the Company's unique circumstances and specific risks must be considered. Accordingly, the cost of equity determined for the proxy group must be adjusted to properly reflect differences in risk when evaluating a fair ROE for UPPCO.

Q36. HOW DO YOU IDENTIFY THE PROXY GROUP OF UTILITIES RELIED ON FOR YOUR ANALYSES?

A36. To evaluate a proxy group of electric utilities, I began with the following criteria:

1. Included in the Electric Utility industry groups compiled by Value Line.
2. Paid common dividends over the last six months and have not announced a dividend cut since that time.
3. No ongoing involvement in a major merger or acquisition that would distort quantitative results.
4. Moody's issuer rating of Baa1, Baa2, or Baa3.
5. S&P corporate credit rating of BBB+, BBB, or BBB-.
6. Value Line Safety Rank of "2" or "3."

Q37. WHAT OTHER PUBLICLY TRADED UTILITIES ARE RELEVANT FOR YOUR ANALYSES?

A37. In addition to the utilities meeting the criteria outlined above, I also considered Algonquin to be relevant for my analyses. With $17 billion in total assets and more than 1 million customer connections, Algonquin's vertically integrated utility assets include power generation facilities and distribution assets throughout North America. Algonquin is publicly traded on the NYSE and has been assigned a BBB credit rating by S&P, which satisfies the criteria discussed above.

Emera Inc. should also be considered in evaluating investors' required rate of return for an electric utility. Emera Inc.'s electric and gas utility operations are comparable to those of the other utilities in the proxy group. Although Value Line currently includes Emera Inc. in its power industry group, rather than its utility groups, Emera Inc.'s operations are dominated by its regulated utility operations, which account for approximately 96% of consolidated net income.[24] Emera Inc.'s Florida and New Mexico utility operations account for 59% of consolidated net income.[25] Emera Inc. has been assigned credit ratings of Baa3 by Moody's and BBB by S&P, which satisfy the criteria discussed above. Thus, investors would regard Algonquin and Emera Inc. as comparable investment alternatives that are relevant to an evaluation of the required rate of return for UPPCO.

These criteria result in the proxy group of 23 companies listed on page 1 of Exhibit A-45 (JST-3), which I refer to as the "Utility Group."

Q38. HOW DO YOU EVALUATE THE INVESTMENT RISKS OF THE UTILITY GROUP?

A38. My evaluation of relative risk considers five published benchmarks that are widely relied on by investors; namely, credit ratings from Moody's and S&P, along with Value Line's Safety Rank, Financial Strength Rating, and beta values. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (*e.g.*, "+" or "-") are used to show relative standing within a category. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. Widely cited in the investment

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[24] Emera, Inc., *Investor Presentation* (March & April 2024). https://s25.q4cdn.com/978989322/files/doc_presentations/2024/Feb/27/mar-apr-2024_marketing-deck.pdf (last visited Mar. 1, 2024).

[25] *Id.*

community and referenced by investors, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. These published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to firm-specific factors.

Finally, beta measures a utility's stock price volatility relative to the market as a whole and reflects the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. Beta is the only relevant measure of investment risk under modern capital market theory and is widely cited in academics and in the investment industry as a guide to investors' risk perceptions. Moreover, in my experience, Value Line is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. … Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[26]

Q39. WHAT DO THESE MEASURES INDICATE WITH RESPECT TO THE OVERALL RISKS OF THE UTILITY GROUP?

A39. The average risk indicators for the Utility Group are shown in the table below:

TABLE 1
UTILITY GROUP RISK INDICATORS

			Value Line		
	S&P	Moody's	Safety Rank	Financial Strength	Beta
Utility Group	BBB+	Baa2	2	B++	0.94

The BBB+ and Baa2 ratings corresponding to the Utility Group place their credit risks solidly within the investment-grade range. Similarly, the average Value Line risk indicators for the Utility Group, which incorporate a broad spectrum of risks, including financial and business position and exposure to company specific factors, are generally indicative of a company with a conservative risk profile.

A. UPPCO's Relative Risks

Q40. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A40. The cost of equity estimates developed later in my testimony are predicated on the investment risk associated with the utilities in the proxy group. This section compares the risks of the Utility Group with those that investors would associate with UPPCO and evaluates the incremental return necessary to compensate for the Company's greater relative risks.

i. Operating Risks

[26] Morin, Roger A., *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 71.

Q41. HOW DO THE CHARACTERISTICS OF UPPCO'S SERVICE TERRITORY DIFFERENTIATE THE COMPANY FROM THE LARGER UTILITIES IN THE PROXY GROUP?

A41. There are a number of considerations that imply greater uncertainties for UPPCO when compared to larger industry counterparts located elsewhere in the United States. UPPCO's service territory is geographically isolated in a relatively vulnerable economic region with exposure to cyclical commodity-based industries. As was mentioned, the Company serves approximately 53,300 electric retail customers in ten of the Upper Peninsula of Michigan's fifteen counties. UPPCO's service territory of 4,460 square miles covers primarily rural countryside, with a customer density of about 12 customers per square mile, and industries served by the Company include forest products, tourism, and manufacturing.[27] The potential for uncertain and extreme weather increases the complexities of operating in such an environment.

Q42. HOW DO WEATHER-RELATED RISKS AFFECT UPPCO'S FINANCIAL POSITION?

A42. In addition to increasing UPPCO's overall risk profile (which in turn has a direct impact on requirements for financial strength), the service territory's exposure to adverse weather impacts has a direct impact on the Company's need for financial strength. UPPCO must maintain ready access to larger reserves of credit and liquidity than most other utilities. Given the high value that UPPCO and its customers place on service availability and reliability, rapid restoration of service after a weather-induced outage is the Company's highest priority. UPPCO must be able to marshal both internal and external resources on a massive scale very quickly, and this leads to large needs for credit and liquidity. Restoration efforts must be funded long before the recovery of

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[27] https://business.keweenaw.org/list/member/upper-peninsula-power-company-houghton-396 (last visited Feb. 28, 2024).

prudently incurred costs can be expected. A financially strong utility will be better prepared to deal with these situations when they inevitably arise, ultimately benefitting impacted customers.

Q43. DO EXTREME WEATHER EVENTS EXPERIENCED IN 2021 HIGHLIGHT THE IMPORTANCE OF MAINTAINING UPPCO'S FINANCIAL INTEGRITY?

A43. Yes. A severe winter storm in February 2021 resulted in uncharacteristically frigid temperatures that disrupted natural gas supplies and power plant operations at a time of unprecedented winter electricity demand. In turn, this produced dramatic spikes in the costs of natural gas and wholesale power throughout the region. As a result, electric and natural gas utilities incurred significant incremental procurement costs to maintain service to customers. Market volatility in the 1970s spurred widespread adoption of automatic adjustment clauses but flowing incremental purchased gas costs through these recovery mechanisms is generally viewed as impracticable given the enormous magnitude of the spike in procurement expenses and the implications for customers' bills. As a result, utilities were required to secure liquidity quickly in order to fund the extraordinary energy costs necessary to maintain service to customers. Continued support for the Company's financial strength is instrumental to ensure that UPPCO can maintain access to the capital necessary to respond effectively under times of turmoil in the energy and capital markets.

Q44. HOW DO UPPCO'S RESIDENTIAL CUSTOMERS COMPARE TO OTHER PARTS OF MICHIGAN AND THE UNITED STATES?

A44. Generally speaking, the Company's customer base in the ten counties it services is characterized by lower per capita income as compared to other parts of Michigan, which itself falls below the United States more broadly on this metric. For example, data from the U.S. Department of Health and Human Services show that median income for the ten counties in UPPCO's service territory averaged $53,336 over the five-year period from 2017 to 2021, as compared to $63,202 for Michigan and $69,021 for the United States.[28] The relatively low-income profile of UPPCO's service territory could exacerbate issues relating to customer affordability.

Q45. HOW DOES THIS EVIDENCE RELATE TO UPPCO'S RISK PROFILE?

A45. Standard economic theory says that at lower levels of income, the demand for goods and services becomes more "price elastic," other things being equal. This means that lower income consumers will be relatively more sensitive to changes in price, and accordingly they will reduce their consumption more when prices increase, as compared to higher income consumers.

Recent inflationary pressures have put upward pressure on utilities' fuel and infrastructure costs. For example, S&P noted listed "unprecedented inflation" as a notable driver in utilities' rate requests in 2022.[29] To the extent that UPPCO is able to pass inflation-induced fuel and infrastructure cost increases along to customers, it stands to reason that the Company's relatively price sensitive customer base could create additional financial risk for UPPCO.

Q46. DOES THE COMPANY'S POWER SUPPLY MIX ADD TO THE COMPANY'S RISK LEVEL?

A46. Yes. The Company's primary source of energy supply is through hydro generation and purchases in the wholesale market. As was mentioned, hydro sources supplied 14.9% of the Company's total energy needs in 2022, and purchases provided 85.1%.[30] Both of these sources entail added risk. While hydropower confers advantages in terms of fuel

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[28] https://hdpulse.nimhd.nih.gov/data-portal/social/table?socialtopic=030&socialtopic_options=social_6&demo=00011&demo_options=income_3&race=00&race_options=race_7&sex=0&sex_options=sexboth_1&age=001&age_options=ageall_1&statefips=26&statefips_options=area_states (last visited Feb. 28, 2024).

[29] S&P Global Market Intelligence, *Inflation rearing its head in electric, gas general rate cases nationwide* (Oct. 4, 2022).

[30] UPPCO 2022 FERC Form 1 at 401a.

cost savings, lack of carbon emissions, and diversity, reduced hydroelectric generation due to below-average water conditions may force the Company to rely more heavily on more costly generating capacity to meet its resource needs. As S&P has observed:

> A reduction in hydro generation typically increases an electric utility's costs by requiring it to buy replacement power or run more expensive generation to serve customer loads. Low hydro generation can also reduce utilities' opportunity to make off-system sales. At the same time, low hydro years increase regional wholesale power prices, creating potentially a double impact – companies have to buy more power than under normal conditions, paying higher prices.[31]

Investors recognize that the potential for volatility in energy markets, unpredictable stream flows, and UPPCO's reliance on wholesale purchases to meet the majority of its resource needs can expose the Company to the risk of reduced cash flows and unrecovered power supply costs. UPPCO's reliance on purchased power to meet shortfalls in hydroelectric generation magnifies the importance of strengthening financial flexibility, which is essential to guarantee access to the cash resources and interim financing required to cover inadequate operating cash flows.

Q47. HOW DOES CLIMATE CHANGE IMPACT INVESTORS' ASSESSMENT OF UPPCO'S RISK EXPOSURE?

A47. The risk posed by climate-related weather events magnifies concerns over the Company's exposure to below-average water conditions. S&P concluded that "water-intensive assets like power plants [are] especially vulnerable in the absence of adaptation," and concluded that water stress is "a serious threat."[32] While noting that the risks of such events are generally manageable under recovery mechanisms that allow related costs to be recuperated, S&P also observed that:

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[31] Standard & Poor's Corporation, *Pacific Northwest Hydrology And Its Impact On Investor-Owned Utilities' Credit Quality*, RatingsDirect (Jan. 28, 2008).

[32] S&P Global Ratings, *Keeping The Lights On: U.S. Utilities' Exposure To Physical Climate Risks*, RatingsDirect (Sep. 16, 2021).

> In the most extreme events, including those of late, utility companies' exposure to acute and chronic climate risks can damage assets or disrupt supplies, which can weaken their financial position and ultimately credit quality.[33]

Q48. WHAT OTHER FACTORS SPECIFIC TO UPPCO'S SERVICE AREA WARRANT CONSIDERATION?

A48. UPPCO's service area is characterized by a high concentration of sales to industrial customers relative to the companies in the Utility Group. Approximately 23.3% of the Company's total electricity sales are to industrial customers,[34] versus an average of 14.2% for the 23 firms in the Utility Group. Because these sales are more sensitive to business cycle changes, the price of alternative energy sources, and pressure from competitors, they are generally considered to be riskier than sales to residential or commercial customers. This exposure to a high concentration of industrial sales implies a significant degree of risk to UPPCO's operations that must be offset by sufficient financial fitness.

Q49. CAN YOU GIVE SPECIFIC EXAMPLES OF THE RISKS ASSOCIATED WITH UPPCO'S VOLATILE INDUSTRIAL CUSTOMER BASE?

A49. Forest products and mining are two of the predominant industries served by the Company. These are cyclical, commodity-based businesses that are susceptible to heavy economic pressure. Indeed, UPPCO has experienced two customer bankruptcies in the paper and mining sectors. NewPage Corporation, with a large paper production center in Escanaba, Michigan, filed for bankruptcy in 2011, temporarily closing its Michigan operations. Verso Corporation acquired NewPage in 2015 but filed for bankruptcy in early 2016, eventually emerging six months later. New Page's and Verso's bankruptcies were some of the largest filings in paper industry sector.

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[33] *Id.*

[34] UPPCO 2022 FERC Form 1 at 304.

Further, in 2016 Cleveland-Cliffs, Inc. announced the closing of the Empire Mine in Ishpeming, Michigan. Finally, another of UPPCO's largest customers, Enbridge Inc., operates a petroleum pipeline under the Straits of Mackinac that has faced long-running challenges due to pipeline integrity concerns.

ii. Regulatory Mechanisms

Q50. WOULD INVESTORS ALSO CONSIDER THE IMPLICATIONS OF REGULATORY MECHANISMS IN EVALUATING UPPCO'S RELATIVE RISKS?

A50. Yes. In response to the increasing sensitivity over fluctuations in costs and the importance of advancing other public interest goals such as reliability, energy conservation and safety, utilities and their regulators have sought to mitigate cost recovery uncertainty and align the interest of utilities and their customers. As a result, adjustment mechanisms, cost trackers, and future test years have become increasingly prevalent, along with alternatives to traditional ratemaking such as formula rates and multi-year rate plans. *RRA Regulatory Focus* concluded in its most recent review of adjustment clauses that:

> More recently and with greater frequency, commissions have approved mechanisms that permit the costs associated with the construction of new generation or delivery infrastructure to be used, effectively including these items in rate base without the need for a full rate case. In some instances, these mechanisms may even provide the utilities a cash return on construction work in progress.
>
> . . . [C]ertain types of adjustment clauses are more prevalent than others. For example, those that address electric fuel and gas commodity charges are in place in all jurisdictions. Also, about two-thirds of all utilities have riders in place to recover costs related to energy efficiency programs, and

> roughly half of the utilities have some type of decoupling mechanism in place.[35]

As shown on Exhibit A-45 (JST-3), and reflective of this trend, the companies in the Utility Group operate under a wide variety of cost adjustment mechanisms, which encompass revenue decoupling and adjustment clauses designed to address rising capital investment outside of a traditional rate case and increasing costs of environmental compliance measures, as well as riders to recover the cost of environmental compliance measures, transmission-related charges, and other costs.

Q51. DO THE REGULATORY MECHANISMS APPROVED FOR THE COMPANY HAVE IMPLICATIONS FOR INVESTORS' EVALUATION OF RELATIVE RISKS?

A51. Yes. UPPCO operates under a limited framework of regulatory adjustment mechanisms or related provisions. In addition to operating under a standard fuel and purchased power cost recovery mechanism, the Company determines its proposed cost of service based on a future test year and has an energy efficiency adjustment mechanism. These mechanisms are designed to recover cost changes on a timely basis, and as such, provide some means of reducing risk for the Company.

However, the mechanisms currently in place for UPPCO are more limited than those approved for other firms in the industry. In contrast to many of the specific operating companies associated with the firms in the Utility Group, the Company lacks cost tracking mechanisms to address ongoing capital investment outside of a traditional rate case. Nor does UPPCO benefit from a normalization adjustment or decoupling mechanism to insulate utility margins from weather fluctuations or declining usage. UPPCO's relative lack of regulatory mechanisms distinguish the Company from the

[35] S&P Global Market Intelligence, *Adjustment Clause: A state-by-state overview*, RRA Regulatory Focus (Jul. 18, 2022).

proxy group, giving investors a basis on which to conclude that UPPCO has relatively higher risk, at least in the dimension of timely cost recovery.

iii. Implications of Firm Size

Q52. HOW DOES A SMALL ELECTRIC UTILITY SUCH AS UPPCO COMPARE TO THE LARGE, PUBLICLY TRADED FIRMS IN YOUR PROXY GROUP?

A52. There is enormous disparity in size between UPPCO and the major participants in the electric utility industry. Consider the 23 utilities making up the Utility Group, for example, which dwarf UPPCO by any measure. For example, where the Utility Group had average annual revenues in 2022 of approximately $9.6 billion and total capital of $29.2 billion, UPPCO had revenues of $116.6 million and total capital of $311.4 million.[36] Similarly, compared with UPPCO's 53,300 customers, on average the firms in the Utility Group supply electric services to 2.4 million customers.

Q53. WHAT DIFFERENCE DOES THIS DISTINCTION IN SIZE MAKE?

A53. The magnitude of the disparity between smaller utilities and the major electric utilities included in the proxy group has important practical implications with respect to the risks faced by UPPCO. All else being equal, it is well accepted that smaller firms are more risky than their larger counterparts, due in part to their inherent lack of diversification and absence of financial resiliency. The financial media has also noted the challenge that UPPCO's size presents, with DBRS Morningstar recently listing the Company's "relatively small size of operations" as one of the primary challenges facing UPPCO.[37]

In the case of a small electric utility, its earnings are principally dependent on the economic, social, regulatory, and other factors affecting its limited service area. This can result in significant exposure, especially where a key employer or industry

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[36] UPPCO 2022 Financial Statements.

[37] DBRS Morningstar, *Upper Peninsula Power Company*, Private Rating Report (Oct. 20, 2023).

dominates the economy. Meanwhile, the large electric utilities generally serve customers in numerous geographic locales, in many cases across multiple states. Thus, where major electric utilities are able to mitigate risks through geographical diversification, small electric companies such as UPPCO are wholly exposed to the uncertainties associated with economic conditions, natural disasters, demographics, and other factors that may impact an extremely small, concentrated service area.

Q54. IS THERE EMPIRICAL EVIDENCE IN THE FINANCIAL LITERATURE THAT A COMPANY'S SIZE AFFECTS ITS RELATIVE RISKS?

A54. Yes. It is well established in the financial literature that smaller firms are more risky than larger firms. For example, Eugene F. Fama and Kenneth R. French concluded in their widely cited study that a firm's relative size is a proxy for risk.[38] Similarly, a classic University of Kansas study demonstrated that large firms are assigned higher bond ratings than small firms with similar characteristics,[39] and there is ample empirical evidence that investors in smaller firms realize higher rates of return than in larger firms.[40] Common sense and accepted financial doctrine hold that these greater risks mean that investors require higher returns from smaller companies, and unless that compensation is provided in the rate of return allowed for a utility, the legal tests embodied in the *Hope* and *Bluefield* cases cannot be met.[41]

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[38] Eugene F. Fama and Kenneth R. French, *The Cross-Section of Expected Stock Returns*, The Journal of Finance (June 1992), p. 429.

[39] George E. Pinches, J. Clay Singleton, and Ali Jahankhani, *Fixed Coverage as a Determinant of Electric Utility Bond Ratings*, Financial Management (Summer 1978).

[40] See for example Rolf W. Banz, *The Relationship Between Return and Market Value of Common Stocks*, Journal of Financial Economics (September 1981) at 16.

[41] Similarly, a study reported in Public Utilities Fortnightly noted that the betas of small companies do not fully account for the higher realized rates of return associated with small company stocks. Michael Annin, *Equity and the Small-Stock Effect*, Pub. Util. Fortnightly (Oct. 15, 1995), at 43.

Q55. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT REQUIRED TO ACCOUNT FOR THIS SIZE PREMIUM?

A55. One estimate of the size premium is available from Kroll,[42] which now reports the widely-recognized Ibbotson Associates data based on historical returns for "Low-Cap" and "Micro-Cap" stocks, in addition to its better-known data series for the S&P 500. Low-Cap companies comprise the 6th through 8th size-deciles of those stocks listed on the New York Stock Exchange, American Stock Exchange, and NASDAQ, while Micro-Cap stocks represent the 9th through 10th size-deciles. These size premiums are shown in the table below.

[42] Kroll, formerly Duff & Phelps, compiles and publishes updated financial data originally presented in *Stocks, Bonds, Bills and Inflation* by Roger G. Ibbotson and Rex A. Sinquefield.

TABLE 2

Decile	Market Capitalization of Smallest Company (in millions)	Market Capitalization of Largest Company (in millions)	Size Premium (Return in Excess of CAPM)
Mid Cap	$ 3,011.224	$ 14,820.048	0.66%
Low Cap	555.880	3,010.806	1.24%
Micro Cap	1.576	554.523	2.91%
Breakdown of CRSP Deciles 1 - 10			
1 - Largest	$ 36,942.976	$ 2,662,326.048	-0.06%
2	14,910.719	36,391.113	0.46%
3	7,493.607	14,820.048	0.61%
4	4,622.261	7,461.284	0.64%
5	3,011.224	4,621.785	0.95%
6	1,864.293	3,010.806	1.21%
7	1,050.083	1,862.491	1.39%
8	555.880	1,046.037	1.14%
9	213.039	554.523	1.99%
10 - Smallest	1.576	212.644	4.70%
Breakdown of CRSP 10th Decile			
10A	$ 97.464	$ 212.644	3.29%
10W	153.796	212.644	2.38%
10X	97.464	153.670	4.43%
10B	$ 1.576	$ 97.398	7.64%
10Y	57.815	97.398	6.22%
10Z	1.576	57.448	10.73%

Source: Kroll, *2023 CRSP Deciles Size Premium,* Cost of Capital Navigator (2024).

As shown above, the individual firms in the Low-Cap group have market capitalizations at or below about $3.0 billion but greater than $556 million, with the market capitalization of Micro-Cap stocks falling between approximately $1.6 million and $555 million. These smaller companies have historically earned higher rates of return than the large companies comprising the S&P 500. For the 1926 to 2023 period, Kroll reported a size premium in excess of the return implied by the CAPM of 124 basis points for the Low-Cap sector, and 291 basis points for Micro-Cap companies.

Q56. HOW ELSE MIGHT THE SIZE PREMIUM BE ESTIMATED FOR UPPCO?

A56. The additional return attributable to the significant distinction in size between UPPCO and the Utility Group can be estimated by reference to the relative size premiums quantified by Kroll for their respective market capitalizations. Because UPPCO does not have publicly traded common stock, its implied market capitalization is estimated by multiplying the Company's total common equity of approximately $186.1 million by the average market-to-book ratio for the Utility Group of 1.57 times. This implies a market capitalization for UPPCO of $292.1 million. As shown above in Table 2, this corresponds to the 9th decile of the publicly-traded firms, which had market capitalizations ranging from $213.0 to $554.5 million and a size premium of 1.99%.

Meanwhile, the average market capitalization for the firms in the Utility Group is $19.9 billion, which corresponds to the 2nd decile. Subtracting the size premium associated with the Utility Group of 46 basis points from the 199 basis-point premium for a firm in the 9th decile results in an implied size adjustment of 153 basis points to reflect the additional risks of UPPCO relative to the much larger electric utilities in the proxy group.

Q57. PLEASE SUMMARIZE THE RISK EXPOSURES INHERENT TO UPPCO AND THE NEED FOR ONGOING SUPPORT OF THE COMPANY'S FINANCIAL STRENGTH AND ABILITY TO ATTRACT CAPITAL ON REASONABLE TERMS.

A57. UPPCO's investors face added risks related to the Company's small size, potentially volatile power supply mix, economically vulnerable service area, and lack of regulatory mechanisms. Nevertheless, UPPCO must simultaneously meet the long-term energy needs of its service area. To continue to meet these challenges successfully and economically, it is crucial that UPPCO receive adequate financial and regulatory support. While providing an ROE that is sufficient to maintain UPPCO's ability to attract capital, even under duress, is consistent with the economic requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to invest in infrastructure and take whatever actions are required to ensure a reliable energy supply. By the same token, customers and the service area economy suffer when the utility is unable to attract necessary capital.

V. CAPITAL MARKET ESTIMATES

Q58. WHAT IS THE PURPOSE OF THIS SECTION?

A58. This section presents capital market estimates of the ROE. First, I discuss the current outlook for capital costs, including expectations for interest rates. Next, I address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. I then describe the DCF, CAPM and risk premium analyses conducted to estimate the cost of common equity for the Utility Group. Finally, I comment on expected earnings and non-utility DCF benchmarks.

A. Outlook for Capital Costs

Q59. PLEASE SUMMARIZE CURRENT ECONOMIC CONDITIONS.

A59. U.S. real GDP contracted 2.2% during 2020, but with the easing of COVID-19 lockdowns, the economic outlook improved significantly in 2021, with GDP growing at a pace of 5.8%, though growth was more subdued in 2022 at 1.9%.[43] More recently, increases in spending by consumers and the federal government led real GDP to grow by 2.5% in 2023.[44] Meanwhile, indicators of employment remain stable, with the national unemployment rate remaining stable at 3.7% in January 2024.[45]

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[43] https://www.bea.gov/news/2024/gross-domestic-product-fourth-quarter-and-year-2023-advance-estimate (last visited Feb. 15, 2024).

[44] *Id.*

[45] https://www.bls.gov/news.release/pdf/empsit.pdf (last visited Feb. 15, 2024).

The underlying risk and price pressures associated with the COVID-19 pandemic were overshadowed by a dramatic increase in geopolitical risks following Russia's invasion of Ukraine in February 2022. These events have also been accompanied by heightened economic uncertainties as inflationary pressures due to COVID-19 supply chain disruptions were further stoked by sharp increases in global commodity prices. The substantial disruption in the energy economy and dramatic rise in inflation led to sharp declines in global equity markets as investors reacted to the related exposures.

Stimulative monetary and fiscal policies, coupled with supply-chain disruptions and rapid price rises in the energy and commodities markets, led to increasing concern that inflation would remain significantly above the Federal Reserve's longer-run benchmark of 2%. In June 2022, CPI inflation peaked at its highest level since November 1981. Since then, CPI inflation has gradually moderated to 3.1% in January 2024.[46] The so-called "core" price index, which excludes more volatile energy and food costs, rose at an annual rate of 3.1% in January 2024.[47] PCE inflation rose 2.6% in December 2023, or 2.9% after excluding more volatile food and energy costs.[48] As Federal Reserve Chair Powell recently noted, "inflation is still too high, ongoing progress in bringing it down is not assured, and the path forward is uncertain."[49]

Investor confidence has also been tested by turmoil in the banking sector, which led to increased volatility in bond and equity markets. The Federal Reserve and U.S. Treasury took quick and dramatic action to shore up banks' liquidity needs and strengthen public confidence in the banking system, but as Moody's noted, "bank stress

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[46] https://www.bls.gov/news.release/pdf/cpi.pdf (last visited Feb. 15, 2024).

[47] *Id.*

[48] https://www.bea.gov/news/2024/personal-income-and-outlays-december-2023 (last visited Feb. 15, 2024).

[49] Federal Reserve, *Transcript of Chair Powell's Press Conference* (Dec. 13, 2023), https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20231213.pdf.

has added uncertainty to the outlook."[50] More recently, heightened geopolitical tensions in the Middle East have led to concerns over possible disruptions in crude oil supplies and attendant price volatility that could deliver another shock to the world economy.

Q60. WHAT IMPACT DO INFLATION EXPECTATIONS HAVE ON THE RETURN THAT EQUITY INVESTORS REQUIRE FROM UPPCO?

A60. Implicit in the required rate of return for long-term capital—whether debt or common equity—is compensation for expected inflation. This is highlighted in the textbook, *Financial Management, Theory and Practice*:

> The four most fundamental factors affecting the cost of money are (1) production opportunities, (2) time preferences for consumption, (3) risk, and (4) inflation.[51]

In other words, a part of investor's required return is intended to compensate for the erosion of purchasing power due to rising price levels. This inflation premium is added to the real rate of return (pure risk-free rate plus risk premium) to determine the nominal required return. As a result, higher inflation expectations lead to an increase in the cost of equity capital.

Q61. HAVE THESE DEVELOPMENTS IMPACTED THE RISKS FACED BY UTILITIES AND THEIR INVESTORS?

A61. Yes. S&P recently revised its outlook for the utility sector to "negative," noting that:

> Credit quality for North American investor-owned regulated utilities has weakened over the past four years, with downgrades outpacing upgrades by more than three times. We expect downgrades to again surpass upgrades in 2024 for the fifth consecutive year.[52]

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[50] Moody's Investors Service, *Baseline US macro forecasts unchanged but outlook more uncertain*, Sector Comment (Apr. 12, 2023).

[51] Eugene F. Brigham, Louis C. Gapenski, and Michael C. Ehrhardt, *Financial Management, Theory and Practice*, Ninth Edition (1999) at 126.

[52] S&P Global Ratings, *Rising Risks: Outlook For North American Investor-Owned Regulated Utilities Weakens*, Comments (Feb. 14, 2024).

S&P cited rising physical risks, as well as weakening financial measures due to rising capital spending and cash flow deficits, and observed that "much of the industry operates with minimal financial cushion from their downgrade threshold."[53]

Meanwhile, Fitch Ratings, Inc. noted that its deteriorating outlook for utilities "reflects continuing macroeconomic headwinds and elevated capex that are putting pressure on credit metrics in the high-cost funding environment."[54] Value Line echoed these sentiments for electric utilities, concluding that:

> **A Challenging Macroeconomic Backdrop Remains**
>
> Inflationary pressure, rising interest rates, and high energy and raw material prices will likely remain a significant burden for most utilities. Inflationary headwinds are raising operating and maintenance costs, as well as fuel prices. Meanwhile, the rising interest rate environment is leading income-oriented investors to the bond market, as well as increasing borrowing costs, which is especially significant for utilities as the usually have low returns on total capital and rely heavily on debt borrowings. We think many of these companies will continue to struggle with the higher costs related to the challenging macroeconomic climate in the near term.[55]

Q62. DO CHANGES IN UTILITY COMPANY BETA VALUES CORROBORATE AN INCREASE IN INDUSTRY RISK?

A62. Yes. Beta measures a stock's price volatility relative to the overall market and reflects the tendency of a stock's price to follow changes in the market. The investment community relies on beta as an important guide to investors' risk perceptions. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. Generally, a higher beta means the market perceives the stock to be riskier than a stock with a lower beta.

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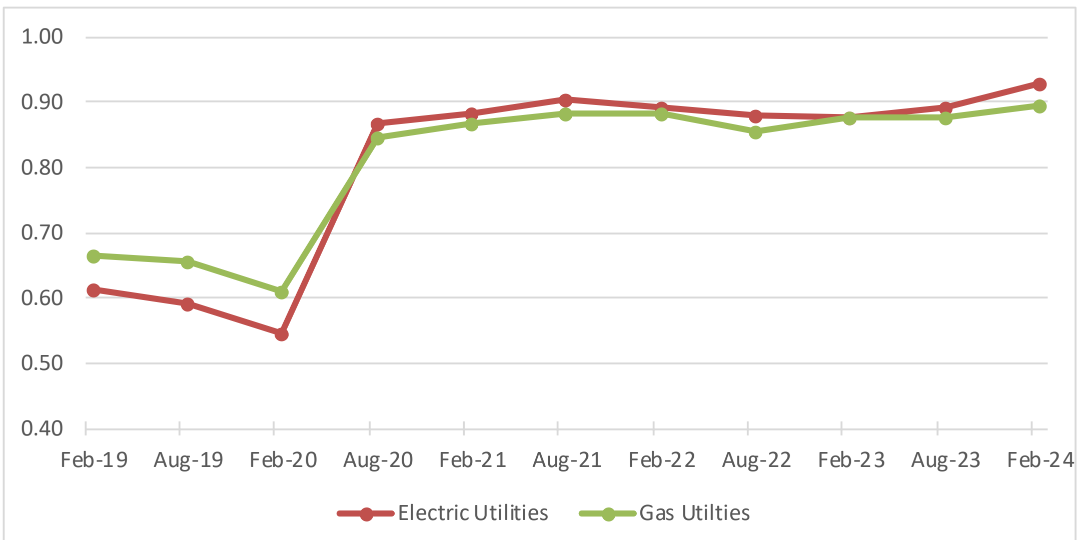
53 *Id.*

54 Fitch Ratings, Inc., *North American Utilities, Power & Gas Outlook 2024* (Dec. 6, 2023).

55 The Value Line Investment Survey, *Electric Utility (Central) Industry* (Sep. 8, 2023) (emphasis original).

The significant shift in pre- and post-pandemic beta values for utilities is illustrated in Figure 1 below. As illustrated there, the average beta value for the electric and gas utilities covered by Value Line increased significantly with the beginning of the pandemic in March 2020, continued to increase during 2021, and have remained elevated. This dramatic increase in a primary gauge of investors' risk perceptions is further proof of the higher risk of electric utility common stocks.

FIGURE 1
UTILITY BETA VALUES



Q63. DO TRENDS IN BOND YIELDS ALSO INDICATE THAT THE COST OF EQUITY HAS INCREASED?

A63. Yes. While the cost of equity is unobservable, the yields on long-term bonds provide a widely referenced benchmark for the direction of capital costs, including required returns on common stocks. Table 3 below compares the average yields on Treasury securities and Baa-rated public utility bonds when UPPCO reached a settlement in its last rate proceeding in May 2019 with those required in January 2024.

TABLE 3
BOND YIELD TRENDS

Series	May 2019	Jan. 2024	Change (bps)
10-Year Treasury Bonds	2.40%	4.06%	166
30-Year Treasury Bonds	2.82%	4.26%	144
Baa Utility Bonds	4.47%	5.73%	126
Average			**145**

Source: https://fred.stlouisfed.org/series/GS30; Moody's Credit Trends.

As shown above, trends in bond yields since UPPCO's currently allowed ROE was authorized document a substantial increase in the returns on long-term capital demanded by investors, and this increase has been sustained in 2024. With respect to utility bond yields—which are the most relevant indicator in gauging the implications for the Company's common equity investors—average yields are now 126 basis points above May 2019 levels.

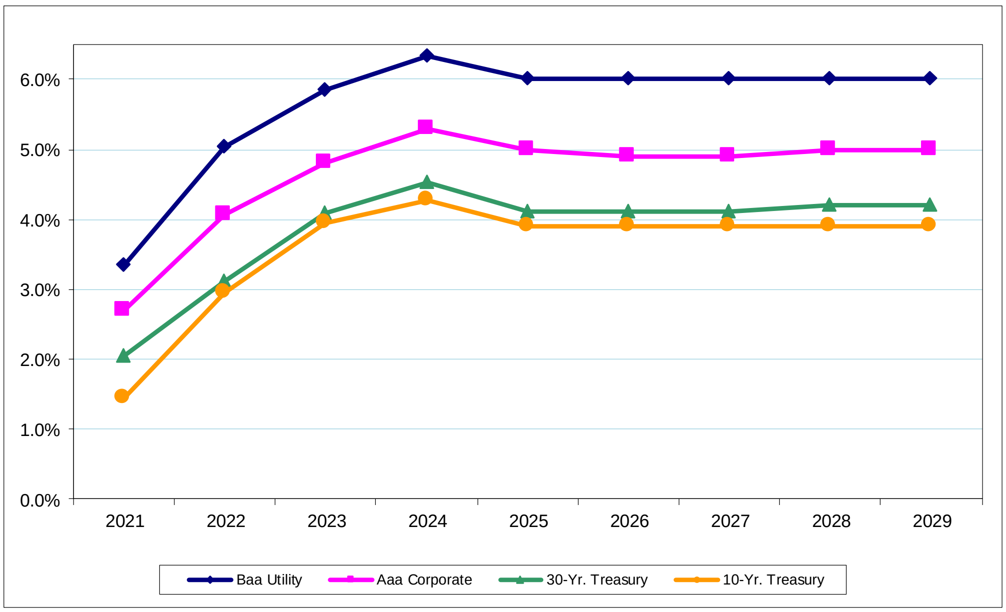
Q64. WHAT IMPLICATIONS DO THESE TRENDS HAVE IN EVALUATING A FAIR ROE FOR UPPCO?

A64. The upward move in interest rates suggests that long-term capital costs—including the cost of equity—have increased significantly in recent years. Exposure to higher interest rates, inflation, and capital expenditure requirements also reinforce the importance of buttressing UPPCO's credit standing, which is under pressure. Considering the potential for financial market instability, competition with other investment alternatives, and investors' sensitivity to risk exposures in the utility industry, greater credit strength is a key ingredient in maintaining access to capital at reasonable cost.

Q65. DO INVESTORS ANTICIPATE THAT THESE HIGHER BOND YIELDS WILL BE SUSTAINED?

A65. Yes. As illustrated in Figure 2 below, the most recent long-term consensus projections from top economists published by Blue Chip document that long-term bond yields are expected to remain elevated when compared to recent historical levels.

FIGURE 2
INTEREST RATE TRENDS



Source: Wolters Kluwer, Blue Chip Financial Forecasts (Dec. 1, 2023); Moody's Investors Service; https://fred.stlouisfed.org/.

This evidence shows that long-term capital costs—including the ROE—have increased substantially, and that investors expect these higher capital costs to be sustained at least through 2029.

Q66. DOES THE PROSPECT FOR CHANGES IN MONETARY POLICY OVER THE COMING YEAR CHANGE THIS CONCLUSION?

A66. No. At the conclusion of the FOMC's January 2024 meeting, Federal Reserve Chair Jerome Powell indicated that "The Committee decided at today's meeting to maintain the target range for the federal funds rate at 5¼ to 5½ percent and to continue the process of significantly reducing our securities holdings."[56] While Chair Powell observed that the Federal Funds rate "is likely at its peak for this tightening cycle," he also stressed that "[t]he economic outlook is uncertain" and "the economy has surprised forecasters in many ways," while reiterating that "ongoing progress toward our 2 percent inflation objective is not assured."[57]

Reuters recently reported that Federal Reserve Bank of New York President John Williams observed "While the economy has come a long way toward achieving better balance and reaching our 2% inflation goal, we are not there yet."[58] Meanwhile, consumer prices rose more than expected in January 2023, resulting in an annual rate of 3.1%.[59] As Chair Powell concluded, "We're prepared to maintain the current target range for the federal funds rate for longer if appropriate."[60]

Q67. WOULD IT BE REASONABLE TO DISREGARD THE IMPLICATIONS OF CURRENT CAPITAL MARKET CONDITIONS IN ESTABLISHING A FAIR ROE FOR UPPCO?

A67. No. Current capital market conditions reflect the reality of the situation in which UPPCO must attract and retain capital. The standards underlying a fair rate of return require an authorized ROE for the Company that is competitive with other investments of comparable risk and sufficient to preserve its ability to maintain access to capital on reasonable terms. These standards can only be met by considering the requirements of

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[56] Federal Reserve, *Transcript of Chair Powell's Press Conference* (Jan. 31, 2024). https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20240131.pdf.

[57] *Id.*

[58] Michael S. Derby, *Fed's Williams sees more work needed to get inflation back to 2%*, Reuters (Feb. 28, 2024). https://www.reuters.com/markets/us/feds-williams-still-ways-go-achieve-2-inflation-goal-2024-02-28/ (last visited Feb. 29, 2024).

[59] Jeff Cox, *Prices rose more than expected in January as inflation won't go away*, CNBC (Feb. 13, 2024). https://www.cnbc.com/2024/02/13/cpi-inflation-january-2024-consumer-prices-rose-0point3percent-in-january-more-than-expected-as-the-annual-rate-moved-to-3point1percent.html (last visited Feb. 29, 2024).

[60] Federal Reserve, *Transcript of Chair Powell's Press Conference* (Jan. 31, 2024). https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20240131.pdf.

investors over the time period when the rates established in this proceeding will be in effect. If the upward shift in investors' risk perceptions and required rates of return for long-term capital is not incorporated in the allowed ROE, the results will fail to meet the comparable earnings standard that is fundamental in determining the cost of capital. From a more practical perspective, failing to provide investors with the opportunity to earn a rate of return commensurate with UPPCO's risks will weaken its financial integrity, while hampering the Company's ability to attract the capital necessary to provide safe and reliable service at the lowest reasonable cost.

B. Discounted Cash Flow Analyses

Q68. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF COMMON EQUITY?

A68. DCF models assume that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[61]

$$P_0 = \frac{D_1}{k_e - g}$$

where: P_0 = Current price per share;
D_1 = Expected dividend per share in the coming year;
k_e = Cost of equity; and,
g = Investors' long-term growth expectations.

The cost of common equity (k_e) can be isolated by rearranging terms within the equation:

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[61] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all the above extend to infinity. Nevertheless, the DCF method provides a workable and practical approach to estimate investors' required return that is widely referenced in utility ratemaking.

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q69. WHAT STEPS ARE REQUIRED TO APPLY THE CONSTANT GROWTH DCF MODEL?

A69. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (g) for the firm. The final step is to add the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

Q70. HOW DO YOU DETERMINE THE DIVIDEND YIELDS FOR THE UTILITY GROUP?

A70. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend is then divided by a 30-day average stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Utility Group are presented on Exhibit A-46 (JST-4). As shown on the first page of this exhibit, dividend yields for the firms in the Utility Group range from 2.0% to 7.1% and average 4.5%.

Q71. WHAT IS THE NEXT STEP IN APPLYING THE CONSTANT GROWTH DCF MODEL?

A71. The next step is to evaluate long-term growth expectations, or "*g*", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q72. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A72. Implementation of the DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. Utility dividend policies reflect the need to accommodate business risks and investment requirements in the industry, as well as potential uncertainties in the capital markets. As a result, dividend growth in the utility industry has lagged growth in earnings as utilities conserve financial resources.

A measure that plays a pivotal role in determining investors' long-term growth expectations is future trends in EPS, which provide the source for future dividends and ultimately support share prices. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in earnings is far more influential than trends in DPS.

The availability of projected EPS growth rates also is key to investors relying on this measure as compared to future trends in DPS. Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of earnings forecasts attests to their relative influence. The fact that securities analysts focus on EPS growth, and that DPS growth rates are not routinely published, indicates that projected EPS growth rates are likely to provide a superior indicator of the future long-term growth expected by investors.

Q73. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE WAY OF GROWTH FOR THE FIRMS IN THE UTILITY GROUP?

A73. The earnings growth projections for each of the firms in the Utility Group reported by Value Line, IBES,[62] and Zacks are displayed on page 2 of Exhibit A-46 (JST-4).

Q74. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS OFTEN ESTIMATED WHEN APPLYING THE CONSTANT GROWTH DCF MODEL?

A74. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Even though these conditions are never met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

The sustainable growth rate is calculated by the formula, $g = br+sv$, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate. Under DCF theory, the "sv" factor is a component of

[62] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Refinitiv and presented at, for instance, https://finance.yahoo.com.

the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. The sustainable, "br+sv" growth rates for each firm in the proxy group are summarized on page 2 of Exhibit A-46 (JST-4), with the underlying details being presented on Exhibit A-47 (JST-5).

The sustainable growth rate analysis shown on Exhibit A-47 (JST-5) incorporates an "adjustment factor" because Value Line's reported returns are based on year-end book values. Since earnings is a flow over the year while book value is determined at a given point in time, the measurement of earnings and book value are distinct concepts. It is this fundamental difference between a flow (earnings) and point estimate (book value) that makes it necessary to adjust to mid-year in calculating the ROE. Given that book value will increase or decrease over the year, using year-end book value (as Value Line does) understates or overstates the average investment that corresponds to the flow of earnings. To address this concern, earnings must be matched with a corresponding representative measure of book value, or the resulting ROE will be distorted. The adjustment factor determined in Exhibit A-47 (JST-5) is solely a means of converting Value Line's end-of-period values to an average return over the year, and the formula for this adjustment is supported in recognized textbooks and has been adopted by other regulators.[63]

Q75. ARE THERE SIGNIFICANT SHORTCOMINGS ASSOCIATED WITH THE "BR+SV" GROWTH RATE?

A75. Yes. First, in order to calculate the sustainable growth rate, it is necessary to develop estimates of investors' expectations for four separate variables; namely, "b", "r", "s", and "v." Given the inherent difficulty in forecasting each parameter and the difficulty of estimating the expectations of investors, the potential for measurement error is

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[63] See, Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 305-306; *Bangor Hydro-Electric Co. et al.*, 122 FERC ¶ 61,265 at n.12 (2008).

significantly increased when using four variables, as opposed to referencing a direct projection for EPS growth. Second, empirical research in the finance literature indicates that sustainable growth rates are not as significantly correlated to measures of value, such as share prices, as are analysts' EPS growth forecasts.[64] The "sustainable growth" approach is included for completeness, but evidence indicates that analysts' forecasts provide a superior and more direct guide to investors' growth expectations. Accordingly, I give less weight to cost of equity estimates based on br+sv growth rates in evaluating the results of the DCF model.

Q76. WHAT COST OF COMMON EQUITY ESTIMATES ARE IMPLIED FOR THE UTILITY GROUP USING THE DCF MODEL?

A76. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on page 3 of Exhibit A-46 (JST-4).

Q77. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE ILLOGICAL ESTIMATES?

A77. Yes. It is essential that the cost of equity estimates produced by quantitative methods pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated.

Q78. HOW DO YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A78. I base my evaluation of DCF estimates at the low end of the range on the fundamental risk-return tradeoff, which holds that investors will only take on more risk if they expect to earn a higher rate of return to compensate them for the greater uncertainly. Because common stocks lack the protections associated with an investment in long-term bonds,

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[64] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 307.

a utility's common stock imposes far greater risks on investors. As a result, the rate of return that investors require from a utility's common stock is considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, DCF results that are not sufficiently higher than the yield available on less risky utility bonds must be eliminated.

Q79. HAVE SIMILAR TESTS BEEN APPLIED BY REGULATORS?

A79. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold.[65] FERC's current practice is to exclude low-end cost of estimates that fall below the six-month average yield on Baa-rated utility bonds, plus 20% of the CAPM market risk premium.[66] In addition, FERC also excludes estimates that are "irrationally or anomalously high."[67] Similarly, the Staff of the Maryland Public Service Commission has also eliminated DCF values where they do not offer a sufficient premium above the cost of debt to be attractive to an equity investor.[68]

Q80. DO YOU EXCLUDE ANY ESTIMATES AT THE LOW OR HIGH END OF THE RANGE OF RESULTS?

A80. Yes. As highlighted on page 3 of Exhibit A-46 (JST-4), I eliminate seventeen low-end DCF estimates ranging from -7.4% to 7.5%. Based on my professional experience and

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[65] See, *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 169 FERC ¶ 61,129 at PP 387, 388 (2019).

[66] Based on the six-month average yield at December 2022 of 5.61% and the 8.1% market risk premium shown on Schedule 6, this implies a current low-end threshold of approximately 7.2%.

[67] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 171 FERC ¶ 61,154 at P 152 (2020).

[68] See, *e.g.*, Maryland Public Service Commission, Case No. 9702, *Direct Testimony and Exhibits of Anson R. Justi* (Dec. 15, 2023) at 33.

the risk-return tradeoff principle that is fundamental to finance, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock. As a result, these values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Also highlighted on page 3 of Exhibit A-46 (JST-4), I eliminate three high-end DCF estimates ranging from 15.5% to 41.2%. The upper end of the remaining DCF results for the Utility Group is set by a cost of equity estimate of 13.7%. While a 13.7% cost of equity estimate may exceed the majority of the remaining values, low-end DCF estimates in the 7.7% to 7.9% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the results, the remaining values provide a reasonable basis on which to frame the range of plausible DCF estimates and evaluate investors' required rate of return.

Q81. WHAT ROE ESTIMATES ARE IMPLIED BY YOUR DCF RESULTS FOR THE UTILITY GROUP?

A81. As shown on page 3 of Exhibit A-46 (JST-4) and summarized in Table 4, below, after eliminating illogical values, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE 4
DCF RESULTS – UTILITY GROUP

Growth Rate	Average	Midpoint
Value Line	9.8%	10.2%
IBES	10.4%	10.4%
Zacks	10.1%	10.8%
br + sv	9.3%	9.6%

C. Capital Asset Pricing Model

Q82. PLEASE DESCRIBE THE CAPM.

A82. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.0, while stocks that tend to move more than the market have betas greater than 1.0. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Under the CAPM formula above, a stock's required return is a function of the risk-free rate (R_f), plus a risk premium that is scaled to reflect the relative volatility of a firm's stock price, as measured by beta (β). Like the DCF model, the CAPM is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q83. WHY IS THE CAPM APPROACH A RELEVANT COMPONENT WHEN EVALUATING THE COST OF EQUITY FOR UPPCO?

A83. The CAPM approach generally is considered to be the most widely referenced method for estimating the cost of equity among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. Because this is the dominant model for estimating the cost of equity outside the regulatory sphere, the CAPM provides important insight into investors' required rate of return for utility stocks, including the Company.

Q84. HOW DO YOU APPLY THE CAPM TO ESTIMATE THE ROE?

A84. Application of the CAPM to the proxy group is based on a forward-looking estimate for investors' required rate of return from common stocks presented in Exhibit A-48 (JST-6). To capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm is obtained from Value Line, and the growth rate is equal to the average of the earnings growth projections for each firm published by IBES, Value Line, and Zacks, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. After removing companies with growth rates that were negative or greater than 20%, the weighted average of the projections for the individual firms implies an average growth rate over the next five years of 10.1%. Combining this average growth rate with a year-ahead dividend yield of 1.9% results in a current cost of common equity estimate for the market as a whole (R_m) of 12.0%. Subtracting a 4.5% risk-free rate based on the average yield on 30-year Treasury bonds for the six month period ending January 2024 produced a market equity risk premium of 7.5%.

Q85. WHAT IS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE CAPM?

A85. As indicated earlier in my discussion of risk measures for the proxy group, I rely on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. … Value Line betas are computed on a theoretically sound basis using a broadly based market

> index, and they are adjusted for the regression tendency of betas to converge to 1.00.[69]

Q86. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE CAPM?

A86. Financial research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size. Accordingly, a modification is required to account for this size effect. As explained by Morningstar:

> One of the most remarkable discoveries of modern finance is that of a relationship between company size and return. … The relationship between company size and return cuts across the entire size spectrum; it is not restricted to the smallest stocks. … This size-rated phenomenon has prompted a revision to the CAPM, which includes a size premium.[70]

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, researchers have developed size premiums that need to be added to account for the level of a firm's market capitalization in determining the CAPM cost of equity.[71] Accordingly, my CAPM analyses also incorporates an adjustment to recognize the impact of size distinctions, as measured by the market capitalization for the firms in the Utility Group.

Q87. WHAT IS THE BASIS FOR THE SIZE ADJUSTMENT?

A87. The size adjustment required in applying the CAPM is based on the finding that *after controlling for risk differences reflected in beta*, the CAPM overstates returns to

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[69] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports (2006) at 71.

[70] Morningstar, *Ibbotson SBBI 2015 Classic Yearbook*, at pp. 99, 108.

[71] Originally compiled by Ibbotson Associates and published in their annual yearbook entitled, *Stocks, Bonds, Bills and Inflation*, these size premia are now developed by Kroll and presented in its *2022 Supplementary CRSP Decile Size Study Data*.

companies with larger market capitalizations and understates returns for relatively smaller firms. The size adjustments utilized in my analysis are sourced from Kroll, who now publish the well-known compilation of capital market series originally developed by Professor Roger G. Ibbotson of the Yale School of Management, and latterly published by Duff & Phelps. Calculation of the size adjustments involve the following steps:

1. Divide all stocks traded on the NYSE, NYSE MKT, and NASDAQ indices into deciles based on their market capitalization.
2. Using the average beta value for each decile, calculate the implied excess return over the risk-free rate using the CAPM.
3. Compare the calculated excess returns based on the CAPM to the actual excess returns for each decile, with the difference being the increment of return that is related to firm size, or "size adjustment."

New Regulatory Finance observed that "small market-cap stocks experience higher returns than large market-cap stocks with equivalent betas," and concluded that "the CAPM understates the risk of smaller utilities, and a cost of equity based purely on a CAPM beta will therefore produce too low an estimate."[72]

Q88. IS THE SIZE ADJUSTMENT INCORPORATED IN YOUR ANALYSIS CONSISTENT WITH HOW FERC APPLIES THE CAPM?

A88. Yes. FERC has observed that "[t]his type of size adjustment is a generally accepted approach to CAPM analyses,"[73] and includes the size adjustment in the CAPM under its ROE methodology for electric utilities and natural gas and oil pipelines.[74] More recently, FERC affirmed its practice of including a size adjustment, concluding that "the

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[72] Roger A. Morin, *New Regulatory Finance* 187 (Pub. Utils. Reports, Inc., 2006).

[73] *Coakley v. Bangor-Hydro-Elec. Co.*, Opinion No. 531-B, 150 FERC ¶ 61,165 at P 117 (2015).

[74] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 (2020); *Policy Statement on Determining Return on Equity for Natural Gas and Oil Pipelines*, 171 FERC ¶ 61,155 (2020).

size adjustment is necessary to correct for the CAPM's inability to fully account for the impact of firm size when determining the cost of equity."[75]

Q89. IS THIS SIZE ADJUSTMENT RELATED TO THE RELATIVE SIZE OF UPPCO AS COMPARED WITH THE PROXY GROUP?

A89. No. The size adjustments used in my application of the CAPM do not relate to UPPCO; rather, they are based on the market capitalization of the firms in the Utility Group. The size adjustments are specific to the CAPM and merely correct for an observed inability of the beta measure to fully reflect the risks perceived by investors for the firms in the proxy group.

Q90. WHAT IS THE IMPLIED ROE FOR THE UTILITY GROUP USING THE CAPM APPROACH?

A90. As shown on Exhibit A-48 (JST-6), after adjusting for the impact of firm size, the CAPM approach implies an average ROE for the Utility Group of 12.2%.

D. Utility Risk Premium

Q91. BRIEFLY DESCRIBE THE RISK PREMIUM METHOD.

A91. The risk premium method extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

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[75] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-B, 173 FERC ¶ 61,159 at P 100 (2020).

Q92. IS THE RISK PREMIUM APPROACH A WIDELY ACCEPTED METHOD FOR ESTIMATING THE COST OF EQUITY?

A92. Yes. The risk premium approach is based on the fundamental risk-return principle that is central to finance, which holds that investors will require a premium in the form of a higher return to assume additional risk. This method is routinely referenced by the investment community and in academia and regulatory proceedings and provides an important tool in estimating a just and reasonable ROE for UPPCO.

Q93. HOW DID YOU IMPLEMENT THE RISK PREMIUM METHOD?

A93. Estimates of equity risk premiums for utilities are based on surveys of previously authorized ROEs. Authorized ROEs presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such ROEs should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, when considered in the context of a complete and rigorous analysis, this data provides a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q94. HOW DID YOU CALCULATE THE EQUITY RISK PREMIUMS BASED ON ALLOWED RETURNS?

A94. The ROEs authorized for electric utilities by regulatory commissions across the U.S. are compiled by S&P Global Market Intelligence and published in its *RRA Regulatory Focus* report. On page 2 of Exhibit A-49 (JST-7), the average yield on public utility bonds is subtracted from the average allowed ROE for electric utilities to calculate equity risk premiums for each year between 1974 and 2023.[76] As shown there, over this period these equity risk premiums for electric utilities average 3.89%, and the yields on public utility bonds average 7.78%.

Q95. IS THERE ANY CAPITAL MARKET RELATIONSHIP THAT MUST BE CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM METHOD?

A95. Yes. The magnitude of equity risk premiums is not constant and equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1% increase or decrease in interest rates, the cost of equity may only rise or fall some fraction of 1%. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have diverged from the average interest rate level represented in the data set.

Current bond yields are lower than those prevailing over the risk premium study period. Given that equity risk premiums move inversely with interest rates, these lower bond yields also imply an increase in the equity risk premium. In other words, higher required equity risk premiums offset the impact of declining interest rates on the ROE.

Q96. IS THIS INVERSE RELATIONSHIP CONFIRMED BY PUBLISHED FINANCIAL RESEARCH?

A96. Yes. There is considerable empirical evidence that when interest rates are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums are greater. This inverse relationship between equity risk premiums and

[76] My analysis encompasses the entire period for which published data is available.

interest rates has been widely reported in the financial literature. As summarized by *New Regulatory Finance*:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose.[77]

Other regulators have also recognized that, while the cost of equity trends in the same direction as interest rates, these variables do not move in lockstep.[78] This relationship is illustrated in the figure on page 3 of Exhibit A-49 (JST-7).

Q97. WHAT ROE IS IMPLIED BY THE RISK PREMIUM METHOD USING SURVEYS OF ALLOWED RETURNS?

A97. Based on the regression output between the interest rates and equity risk premiums displayed on page 3 of Exhibit A-49 (JST-7), the equity risk premium for electric utilities increases by approximately 42 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit A-49 (JST-7) with an average yield on public utility bonds for the six month period ending January 2024 of 5.85%, this implies a current equity risk premium of 4.71% for electric utilities. Adding this equity risk premium to the average yield on Baa utility bonds for the six-month period ending January 2024 implies a current ROE of 10.79%.

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77 Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports (2006) at 128.

78 *See, e.g.*, California Public Utilities Commission, Decision 08-05-035 (May 29, 2008); Entergy Mississippi Formula Rate Plan FRP-7, https://cdn.entergy-mississippi.com/userfiles/content/price/tariffs/eml_frp.pdf (last visited Mar. 12, 2024); *Martha Coakley et al.*, 147 FERC ¶ 61,234 at P 147 (2014).

E. Recommended ROE for UPPCO

Q98. ARE THE RESULTS OF YOUR ANALYSES DIRECTLY APPLICABLE TO UPPCO?

A98. No. As documented in my testimony and summarized below, there are significant distinctions between the risks faced by UPPCO and those of the large, publicly traded electric utilities that make up the proxy group:

- UPPCO's operating risks are heightened due to its limited service territory, exposure to variability in hydroelectric generation and wholesale power costs, its high dependence on industrial load, and its lack of economies of scale.
- The utilities in my proxy group operate under a wider variety of regulatory mechanisms than does UPPCO, which allows them to better mitigate the risks of fluctuations in sales and costs and regulatory lag associated with incremental investment.
- There is enormous disparity in size between UPPCO and the electric utilities in the proxy group used to estimate the cost of equity. It is well established that smaller firms are more risky than larger firms, with the results of widely recognized financial research indicating a size adjustment of approximately 153 basis points to reflect the additional risks of UPPCO relative to the much larger electric utilities in the proxy group.
- As reflected in the testimony of Company witness Kates, UPPCO is requesting a fair ROE of 10.7%, which represents a conservative ROE for the Company.

Q99. PLEASE SUMMARIZE THE ROE RECOMMENDATION THAT RESULTS FROM YOUR ANALYSES.

A99. Based on the results of the DCF, CAPM and risk premium analyses discussed above, I conclude that 10.4% to 11.4% represents a reasonable ROE range for a hypothetical utility that is similar in overall investment risk to the Utility Group. UPPCO's small size, limited service territory, exposure to large industrial customers, power supply mix and relative lack of regulatory mechanisms would warrant an ROE at the top of my recommended range. Given that UPPCO is requesting a 10.7% ROE, I consider UPPCO's requested ROE to be conservative.

Q100. WHAT OTHER FACTORS SHOULD BE CONSIDERED IN EVALUATING A FAIR ROE FOR THE COMPANY?

A100. Apart from the results of the quantitative methods summarized above, it is crucial to recognize the importance of supporting UPPCO's financial position so that UPPCO remains prepared to respond to unforeseen events that may materialize in the future. Past challenges in the capital markets and ongoing economic uncertainties highlight the benefits of continuing to support the Company's financial strength to ensure that UPPCO can attract the capital needed to maintain reliable service at a lower cost for customers.

VI. BENCHMARK ANALYSES

Q101. DO YOU ALSO CONSIDER AN EXPECTED EARNINGS BENCHMARK IN EVALUATING AN ROE FOR UPPCO?

A101. Yes. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is consistent with the economic underpinnings for a just and reasonable rate of return established by the U.S. Supreme Court in *Bluefield* and *Hope*.[79] Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors. This analysis is not relied on to arrive at my recommended ROE range of reasonableness; however, it is my opinion that this is a relevant consideration in evaluating a just and reasonable ROE for UPPCO's electric utility operations.

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[79] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

Q102. WHAT ECONOMIC PREMISE UNDERLIES THE EXPECTED EARNINGS APPROACH?

A102. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. While I am not a lawyer and do not offer a legal opinion, from my position as a financial economist such an outcome would violate the *Hope* and *Bluefield* standards and undermine the utility's access to capital on reasonable terms.

Q103. HOW IS THE EXPECTED EARNINGS APPROACH TYPICALLY IMPLEMENTED?

A103. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Moreover, regulators do not set the returns that investors earn in the capital markets, which are a function of dividend payments and fluctuations in common stock prices - both of which are outside their control. Regulators can only establish the allowed ROE, which is applied to the book value of a utility's investment in rate base, as determined from its accounting records. This is analogous to the expected earnings approach, which measures the return that investors expect the utility to earn on book value. As a result, the expected earnings approach provides a meaningful guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This expected earnings test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q104. WHAT ROE BENCHMARK IS INDICATED FOR UPPCO BASED ON THE EXPECTED EARNINGS APPROACH?

A104. For the firms in the proxy group, the year-end returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit A-50 (JST-8). As I explained earlier in my discussion of the br+sv growth rates used in applying the DCF model, Value Line's returns on common equity are calculated using year-end equity balances, which understates the average return earned over the year.[80] Accordingly, these year-end values were converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit A-47 (JST-5). As shown on Exhibit A-50 (JST-8), Value Line's projections suggest an average ROE of 10.8% for the Utility Group.

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[80] For example, to compute the annual return on a passbook savings account with a beginning balance of $1,000 and an ending balance of $5,000, the interest income would be divided by the average balance of $3,000. Using the $5,000 balance at the end of the year would understate the actual return.

Q105. WHAT OTHER PROXY GROUP DO YOU CONSIDER IN EVALUATING A ROE FOR UPPCO?

A105. Consistent with underlying economic and regulatory standards, I also apply the DCF model to a reference group of low-risk companies in the non-utility sector of the economy. I refer to this group as the "Non-Utility Group." Like the expected earnings benchmark, this analysis is not relied on to arrive at my recommended ROE range of reasonableness.

Q106. DO UTILITIES HAVE TO COMPETE WITH NON-REGULATED FIRMS FOR CAPITAL?

A106. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly, the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment, and there is a plethora of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. Indeed, modern portfolio theory is built on the assumption that rational investors will hold a diverse portfolio of stocks, not just companies in a single industry.

Q107. IS IT CONSISTENT WITH THE *BLUEFIELD* AND *HOPE* CASES TO CONSIDER INVESTORS' REQUIRED ROE FOR NON-UTILITY COMPANIES?

A107. Yes. The cost of equity capital in the competitive sector of the economy forms the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties." It does not restrict consideration to other utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[81]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Q108. DOES CONSIDERATION OF THE RESULTS FOR THE NON-UTILITY GROUP IMPROVE THE RELIABILITY OF DCF RESULTS?

A108. Yes. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry, or by the industry falling into favor or disfavor by analysts. Such distortions could result in biased DCF estimates for utilities. Because the Non-Utility Group includes low risk companies from more than one industry, it helps to insulate against any possible distortion that may be present in results for a particular sector.

Q109. WHAT CRITERIA DO YOU APPLY TO DEVELOP THE NON-UTILITY GROUP?

A109. My comparable risk proxy group was composed of those United States companies followed by Value Line that:

1) pay common dividends;
2) have a Safety Rank of "1";
3) have a Financial Strength Rating of "A" or greater;
4) have a beta value of 0.95 or less; and
5) have investment grade credit ratings from Moody's and S&P.

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81 *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 391 (1944).

Q110. HOW DO THE OVERALL RISKS OF THIS NON-UTILITY GROUP COMPARE WITH THE UTILITY GROUP?

A110. Table 5 compares the Non-Utility Group with the Utility Group across the measures of investment risk discussed earlier.

TABLE 5
COMPARISON OF RISK INDICATORS

			Value Line		
	S&P	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Non-Utility Group	A-	A2	1	A+	0.79
Utility Group	BBB+	Baa2	3	B++	0.95

As shown above, the risk indicators for the Non-Utility Group generally suggest less risk than for the Utility Group.

The companies that make up the Non-Utility Group are representative of the pinnacle of corporate America. These firms, which include household names such as Coca-Cola, Procter & Gamble, and Walmart, have long corporate histories, well-established track records, and exceedingly conservative risk profiles. Many of these companies pay dividends on a par with utilities, with the average dividend yield for the group of 2.0%.[82] Moreover, because of their significance and name recognition, these companies receive intense scrutiny by the investment community, which increases confidence that published growth estimates are representative of the consensus expectations reflected in common stock prices.

Q111. WHAT ARE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY GROUP?

A111. I applied the DCF model to the Non-Utility Group using the same analysts' EPS growth projections described earlier for the Utility Group. The results of my DCF analysis for

[82] Exhibit A-51 (JST-9), page 1.

the Non-Utility Group are presented in Exhibit A-51 (JST-9). As summarized in Table 6, after eliminating illogical values, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE 6
DCF RESULTS – NON-UTILITY GROUP

Growth Rate	Average	Midpoint
Value Line	10.4%	11.0%
IBES	10.4%	11.0%
Zacks	10.7%	11.3%

As discussed earlier, reference to the Non-Utility Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Because the actual cost of equity is unobservable, and DCF results inherently incorporate a degree of error, cost of equity estimates for the Non-Utility Group provide an important benchmark in evaluating a just and reasonable ROE for UPPCO.

VII. CAPITAL STRUCTURE

Q112. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS RETURN ON EQUITY?

A112. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow that will remain.

Q113. WHAT COMMON EQUITY RATIO IS IMPLICIT IN UPPCO'S STRUCTURE?

A113. As supported in the testimony of Company witness Kates, UPPCO is requesting that its rates be set using its projected test year capital structure ending December 31, 2025, with a common equity ratio of approximately 51.5%.

Q114. HOW DOES THIS COMPARE TO THE AVERAGE CAPITALIZATION MAINTAINED BY THE UTILITY GROUP?

A114. As shown on page 1 of Exhibit A-52 (JST-10), common equity ratios for the individual firms in the Utility Group range from a low of 33.0% to a high of 70.2% at year-end 2022, and averaged 45.0%. Meanwhile, the three-to-five year forecasts published by Value Line result in common equity ratios ranging from 27.0% to 59.5% for the Utility Group, with an average of 44.6%.

Q115. ARE THERE OTHER INDUSTRY BENCHMARKS THAT ARE MORE RELEVANT IN EVALUATING UPPCO'S CAPITAL STRUCTURE?

A115. Yes. The capital structures maintained by other operating electric utilities provide a direct guide to financing policies that are consistent with industry-specific risks and the need to maintain adequate borrowing capacity and financial flexibility.

Q116. WHAT CAPITALIZATION RATIOS ARE MAINTAINED BY COMPARABLE UTILITY OPERATING COMPANIES?

A116. Pages 2 and 3 of Exhibit A-52 (JST-10) display capital structure data for the most recently available annual period for the group of electric utility operating companies owned by the firms in the Utility Group used to estimate the cost of equity. As shown there, based on the most recent year-end data available, common equity ratios for these utilities range from 40.1% to 80.4% and average 52.5%.

Q117. DO ONGOING ECONOMIC AND CAPITAL MARKET UNCERTAINTIES ALSO INFLUENCE THE APPROPRIATE CAPITAL STRUCTURE FOR UPPCO?

A117. Yes. Financial flexibility plays a crucial role in ensuring the wherewithal to meet funding needs, and utilities with higher financial leverage may be foreclosed or have limited access to additional borrowing, especially during times of stress. As Moody's observed:

> Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to capital markets to assure adequate sources of funding and to maintain financial flexibility. During times of distress and when capital markets are exceedingly volatile and tight, liquidity becomes critically important because access to capital markets may be difficult.[83]

More recently, Moody's emphasized that the utility sector "is likely to continue to generate negative free cash flow and credit quality is likely to suffer unless utilities fund this negative free cash flow appropriately with a balance of debt and equity financing."[84]

S&P confirmed the financial challenges associated with funding heightened investment in the utility sector, noting that, "About one-third of the industry is strategically managing their financial performance with only minimal financial cushion," and warning that "when unexpected risks occur or base-case assumptions deviate from expectations, the utility's credit quality can weaken."[85] More recently, S&P added that "given the current high percentage of negative outlooks, we anticipate that 2024 will be another challenging year for the industry's credit quality."[86]

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[83] Moody's Investors Service, *FAQ on credit implications of the coronavirus outbreak*, Sector Comment (Mar. 26, 2020).

[84] Moody's Investors Service, *Regulate Electric and Gas Utilities – US, Rising capital expenditures will require higher annual equity funding*, Sector In-Depth (Nov. 8, 2023).

[85] S&P Global Ratings, *The Outlook For North American Regulated Utilities Turns Stable* (May 18, 2023).

[86] S&P Global Ratings, *Rising Risks: Outlook For North American Investor-Owned Regulated Utilities Weakens*, Comments (Feb. 14, 2024).

As a result, the Company's capital structure must maintain adequate equity to preserve the flexibility necessary to maintain continuous access to capital even during times of unfavorable energy or financial market conditions.

Q118. WHAT DOES THIS EVIDENCE SUGGEST WITH RESPECT TO THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A118. Based on my evaluation, I conclude that UPPCO's requested capital structure represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return. While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well its specific financing needs and access to capital. A public utility with an obligation to serve must maintain ready access to capital so that it can meet the service requirements of its customers, and financing must be continuously available, even during unfavorable capital market conditions.

Unlike the firms in the Utility Group, UPPCO lacks the benefits that come from diversified service territories and substantial scope and size. Moreover, as discussed earlier, the Company is exposed to a high concentration of industrial sales, which are susceptible to greater volatility. UPPCO also does not benefit from revenue decoupling or cost tracking mechanisms that are widely prevalent in the utility industry. These factors imply a significantly elevated level of business risk relative to other electric utilities. These risks are further compounded through the increased use of financial leverage. As a result, UPPCO must balance its higher business risks by moderating its reliance on debt financing. Considering the need to maintain financial flexibility and accommodate the additional business risks associated with the Company, UPPCO's capital structure represents a reasonable mix of capital sources from which to calculate the overall rate of return.

Q119. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A119. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
***

In the matter of the application of	)	
UPPER PENINSULA POWER COMPANY	)	
for authority to increase its rates for the generation	)	Case No. U-21555
and distribution of electricity and other relief.	)	
	)	

DIRECT TESTIMONY AND EXHIBITS OF

JAY R. RINGLER

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

March 21, 2024

Q. Please state your name, business address and position.

A. My name is Jay R. Ringler. My business address is 18494 Canal Rd, Houghton, MI. I am the Director of Distribution Asset Management for Upper Peninsula Power Company ("UPPCO" or the "Company").

Q. For whom are you providing testimony?

A. I am providing testimony on behalf of UPPCO in support of its request for an increase in its retail electric rates.

Q. Please describe briefly your educational, professional, and utility background.

A. I have a Bachelor of Science Degree from Michigan Technological University, in Electrical Engineering and have 33 years of experience in the electric utility industry. I began my career with Wisconsin Public Service Corporation ("WPS Corp") in March 1991 at the Kewaunee Nuclear Plant in the Engineering Support Department, as an Electrical Engineer. Thereafter, I worked for WPS Corp in various positions including, Electric Distribution Planning Engineer and Regional Electric Engineer. In April 2000, I transferred to UPPCO as General Foreman, and promoted to Customer Service Manager, then to Technical Services Manager, and later as Manager of Distribution Engineering in May 2015. My current position as UPPCO's Director of Distribution Asset Management began in April 2023.

PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to describe and provide support for UPPCO's distribution System Hardening and Reliability Projects ("SHARP"), including the Company's focus on strategic undergrounding projects which are aimed to bolster system reliability and service quality for customers.

EXHIBITS

Q. Are you sponsoring any Exhibits in this proceeding?

A. Yes. I am sponsoring the following Exhibits, which were either prepared by me or under my direct supervision:

1. Exhibit No. A-7, Schedule B5.4 (JRR/DJG-1), Proposed Distribution & Substation CAPEX by Business Driver
2. Exhibit No. A-13 (JRR-2), UPPCO Line Clearance History
3. Exhibit No. A-21 (JRR-3), UPPCO Distribution CAPEX
4. Exhibit No. A-23 (JRR-4), 2019-2023 Reliability Indices
5. Exhibit No. A-24 (JRR-5), 2019-2023 Major Event Days
6. Exhibit No. A-25 (JRR-6), 2019-2023 Outages by Cause
7. Exhibit No. A-26 (JRR-7), 2019-2023 Pole Inspection History
8. Exhibit No. A-27 (JRR-8), 2019-2023 Underground Inspection History
9. Exhibit No. A-28 (JRR-9), 2019-2023 Underground Outage History
10. Exhibit No. A-29 (JRR-10), 2019-2023 Historical Maintenance Costs
11. Exhibit No. A-30 (JRR-11), 2022-2023 Overhead to Underground Projects
12. Exhibit No. A-31 (JRR-12), 2024-2025 System Hardening & Reliability Projects

Q. How is your testimony organized regarding distribution system reliability?

A. My testimony is organized as follows:

1. Distribution System Conditions
2. Local System Load Forecasts
3. Reliability Metrics and System Goals
4. Maintenance and Upgrade Plans
5. Capital Expenditure Decision Criterion
6. Customer Value Determination
7. Response to U-21286 Rate Case Settlement
8. System Hardening & Reliability Projects

Distribution System Conditions

Q. Please provide an overview of UPPCO's distribution system conditions.

A. UPPCO serves approximately 59,000 meters in Michigan's Upper Peninsula with a service territory of approximately 4,500 square miles in 10 of the 15 counties in the Upper Peninsula. UPPCO's distribution system includes approximately 4,500 line-miles of overhead and underground conductor routed primarily in non-urban areas. The overhead lines consist of approximately 2,170 miles of primary, 596 miles of secondary, and 520 miles of service line. The underground lines consist of approximately 810 miles of primary, 45 miles of secondary, and 378 miles of service line. Therefore, UPPCO's distribution system is comprised of approximately 73% overhead conductor and 27% underground conductor. Much of UPPCO's rural distribution system is routed off the road right-of-way, along lakes, and in cross-country areas that are difficult to access. The result is approximately 13 meters per line mile of distribution system over a heavily wooded service territory.

UPPCO's overhead system is supported primarily on approximately 73,000 wood poles with an average age of 39 years. The expected life of a typical utility pole is 40-years. Nearly 50% of UPPCO's poles were installed prior to 1981, making these poles 44 years old or older, which is beyond the expected life. Poles weaken with age and are more likely to fail during storm conditions.

A significant amount of UPPCO's underground cable was installed in the 1970s with 175 mil insulation and a bare concentric neutral. This vintage of cable is more prone to faults, and the neutral could corrode causing a safety hazard and overcurrent protection issues.

Local System Load Forecasts

Q. Please provide an overview of local system load forecasts.

A. UPPCO performs a detailed forecast on an annual basis. This data is used to feed the ATC load forecast which is in turn used to feed into the MISO load forecast. The forecast is based on UPPCO's system coincident peak demand for the summer season loads. UPPCO's 10-year annual average system load growth from 2014 to 2023 was 1.9%.

Reliability Metrics & System Goals

Q. Please provide an overview of UPPCO's reliability metrics and goals.

A. For reliability metrics, UPPCO has used the Institute of Electrical and Electronic Engineers ("IEEE") Guide for Electric Distribution Reliability Indices, Standard 1366, since 2012. SAIDI ("System Average Interruption Duration Index"), SAIFI ("System Average Interruption Frequency Index"), and CAIDI ("Customer Average Interruption Duration Index") are often used to compare performance among utilities.

As evidenced in Exhibit A-23 (JRR-4), 2019 – 2023 Reliability Indices, UPPCO's 5-year reliability data is shown for All-Weather conditions and Excluding Major Event Days ("MEDs"). This reliability data has been filed annually with the MPSC under Docket U-12270 since 2013.

Please note, UPPCO removes transmission-caused outages from its filed reliability indices calculations based on language in IEEE 1366-2022, Section 6.2, stating, "Interruptions that occur as a result of outages on customer-owned facilities, or loss of supply from another utility, should not be included in the index calculation." Transmission is defined as greater than 50,000 volts. UPPCO does not own any transmission lines. Transmission service is provided through the American Transmission Company ("ATC"), which is another utility, so outages caused by loss of transmission should not be included in UPPCO-specific reliability indices.

The Michigan Public Service Commission ("MPSC") has created "MI Power Grid" to outline performance requirements and improve service quality and electric reliability in Michigan. UPPCO is trying to improve the resilience and reliability of the Company's distribution system in order to meet the Michigan reliability goals and improve the customer experience. UPPCO sets an aggressive SAIDI goal each year based on 90% of the previous 5-year average SAIDI, excluding MEDs. The goal for 2024 is 164 minutes.

In 2023, excluding transmission-caused events and major event days ("MEDs"), UPPCO's SAIDI was 141 minutes and SAIFI was 1.0 events per average UPPCO customer. However, including MEDs, UPPCO's 2019-2023 5-year average SAIDI was 446 minutes, and UPPCO's SAIFI was 1.4 events per average UPPCO customer. For this reason, UPPCO continuously strives to improve its customer experience by increasing system reliability and resilience and accounts for MEDs in its reliability improvement project planning.

As evidenced in Exhibit A-24 (JRR-5), Major Event Days ("MEDs"), UPPCO represents the Threshold for a Major Event Day ("TMED") from 2019-2023 as well as the number of MEDs experienced per year. Please note that there was only one MED in each of the years 2020 and 2021, but five in 2019 and four in 2022. Although MEDs are removed from the data, there is overlap of outages on the adjacent days before and after an MED which are not included in the MED, since MEDs are from midnight to midnight, statistically, regardless of when the storm actually started. Partial storm days may or may not meet the threshold of an MED and a storm starting midday and ending the following midday may result in daily SAIDIs that, if added together, would equate to an MED, but are not counted as an MED. In UPPCO's experience, even though an MED ends at midnight, storm restoration efforts may continue into the following days accumulating daily SAIDI minutes that do not reach the threshold of an MED.

Referring back to Exhibit A-23, 2019 – 2023 Reliability Indices, and comparing 2019 SAIDI and SAIFI data to 2023 excluding MEDs, the data would indicate that UPPCO's reliability is improving, and its metrics are on a downward trend. However, the decline has not been a straight line over this period. The reason is that the impact of major storms has a dramatic effect on the indices. UPPCO experienced 4 MEDs out of 5 consecutive days in late November and into December in 2019 during a catastrophic storm event. In 2020, UPPCO experienced only one MED, however, two other dates had daily SAIDI's of 17.1 minutes, which were just under the threshold of a major event day ("TMED ") of 17.4 minutes, plus three other dates had daily SAIDIs in the range of 13-15 minutes, for a total of five dates with double-digit SAIDI minutes that did not escalate to the level of an MED. By way of comparison, in 2021, UPPCO also recorded a single MED, but experienced only two double-digit SAIDI days of 13 and 16 minutes. In 2022, four MEDs were recorded but experienced four dates with daily SAIDIs of 10, 10, 15, and 16 minutes which are less than the TMED. Therefore, small differences in the daily SAIDI can have a big impact on the cumulative SAIDI over the course of a year. However, given the variability of weather-related events from year to year, it appears UPPCO's past capital expenditures for storm hardening and reliability improvements, combined more aggressive line clearance efforts to remove dead and dying trees outside the utility right-of-way, have reduced and will continue to lessen UPPCO's SAIDI over time.

As evidenced in Exhibit A-25 (JRR-6), Outages by Cause, UPPCO depicts the 5-year average from 2019-2023 of all sustained outages by cause sorted by SAIDI. Vegetation-related outages represent the highest percentage of causes in terms of SAIDI minutes at 45% and 44% for both all-weather conditions and excluding MEDs, respectively, followed closely by weather-related causes at 33% for all-weather conditions; equipment-related events are the second highest cause when excluding MEDs at 17%, followed closely by weather-related events, including lightning, at 15%. In addition, in terms of the number of outage events and the number of customers affected, vegetation-related outages top the list under both all-weather conditions and excluding MEDs and emphasizes the need to maintain UPPCO's on-cycle line clearance program. UPPCO places a high priority on line clearance, which has significantly aided in the downward trend of the aforementioned reliability metrics. Following UPPCO's accelerated line clearance program from 2014 to 2017, UPPCO has maintained a 6-year line clearance cycle thereafter.

Maintenance & Upgrade Plans

Q. Please provide an overview of UPPCO's maintenance and upgrade plans.

A. Strong winds are predominantly the cause of tree-related outages, and most tree-related outages in the last few years are due to off-road right-of-way ("ROW") trees falling onto the line, not from trees growing into the line or from dead trees just falling over. While the weather is quite unpredictable and uncontrollable, a systematic line clearance program can greatly aid in both reducing the number of tree-related outages and in improving the utility's ability to respond to and restore the system in a timely manner. When UPPCO seeks competitive bids, it details specifications for line clearance that its contractors must follow, which include the identification and removal of hazard trees located off the normal utility clearance right-of-way which may pose an imminent danger to the system. UPPCO's line clearance has been improving for many years, and the

Company has completed its previously approved accelerated line clearance project which ran from 2014 to 2017. With this completion of this accelerated program, the Company has maintained a 6-year cycle for its system.

Trained and experienced contractors as well as the UPPCO Line Clearance Coordinator have the ability to identify trees that have become hazards each day in the field. Tree diseases, caused by the Spruce Bud Worm, Emerald Ash Borer, as well as Beech Tree Disease, and Oak Wilt, have become prominent in UPPCO's service territory and have significantly changed the line clearance program. We have found the cost to address areas where dead and dying trees are present is approximately double the cost of an area without dead and dying trees. Cost factors include extensive tree removals, contact and negotiation with customers and landowners for off ROW trees as well disposal of the large amount of tree debris caused by the removals.

For line clearance, UPPCO's current utility right-of-way only extends 10-feet beyond the edge of the conductor. So, even when line clearance is performed to specifications, a 70-foot tree growing off the utility ROW can still easily fall into a pole line located 35 feet above ground and cause an outage. In fact, any tree 40-feet tall or larger could contact a line 35 feet above ground.

In addition to its line clearance program, UPPCO must also undertake many different activities to make its system less susceptible to outages, reduce the number of customers affected by any single outage, and make the system more flexible so outages can be restored more quickly.

One effective way to become more resilient to outages is to "harden" the distribution system from storm activity.

Q. Please list the components of UPPCO's storm hardening practices.

A. UPPCO's storm hardening practices include:

1. Line Clearance
2. Overhead Inspections
3. Underground Inspections
4. Rerouting Overhead to Underground
5. Replacing Existing Poles with Taller or Stronger Poles
6. Effective Shared Facilities Program
7. Enhanced Restoration Process
8. Optimize Technology

I will describe each of these in more detail as follows.

Q. Is line clearance an important part of the Company's storm hardening practices?

A. Yes. As previously mentioned, UPPCO has detailed line clearance specifications, and the management of the vegetation in proximity to the distribution system is now on cycle. Maintaining an on-cycle line clearance program reduces potential outages due to falling trees, but also provides crews with good accessibility to locate and restore service in a timely manner. Additionally, a line clearance process that is on-cycle avoids future costs to reclaim overgrown ROW; that is, UPPCO contends that maintaining a line clearance program on cycle is less costly in the long run than reclaiming ROW when an overhead distribution system becomes overgrown due to cycle slippage or neglect.

Q. Please describe UPPCO's line clearance process?

A. UPPCO has approximately 2,200 miles of overhead primary conductor right-of-way which must be trimmed on a regular basis in order to provide a safe and reliable electrical distribution system for the Company's customers and the general public. Also, UPPCO also clears right-of-way to ensure enough access to restore service in the event of a weather or non-weather-related outage. UPPCO trims vegetation around its overhead lines to a standard utility specification which includes identifying and removing hazard trees that are imminent of falling on power lines. The majority of UPPCO's distribution system lies within county road right-of-way providing limited clearance thus requiring private easements or permissions to be secured for line clearance activities beyond this boundary. With many of our native tree species towering in excess of 70 feet and in relatively close proximity to the line, this still proves adequate for a typical healthy forest trimmed in good fashion taking into account tree growth and canopy spread over the years, hence the 6-year cycle approach used by UPPCO. However, the last several years have seen a drastic increase in off-right-of-way dead and dying trees stemming from several harmful diseases or insect infestation root causes impacting tree mortality in our service area which has, in turn, caused a drastic increase in both the quantity and associated costs to address these potential threats to reliability. UPPCO also completes vegetation management of selected underground rights-of-way in rural areas that are becoming unidentifiable and inaccessible for operation and maintenance.

Q. Has UPPCO successfully maintained an on-cycle 6-year line clearance program?

A. Yes. Please reference Exhibit A-13 (JRR-2), UPPCO Line Clearance History, which indicates the miles of line cleared in each UPPCO district as well as the associated costs.

To summarize, UPPCO cleared the following line miles over the past 5 years:

2019 375 miles

2020 382 miles

2021 376 miles

2022 375 miles

2023 377 miles

Q. In calendar years 2024 and 2025, how many line miles will UPPCO be targeting for its distribution line clearance program?

A. As stated above, UPPCO intends to continue its 6-year vegetation management cycle and is targeting to trim no less than 372 line-miles per year.

Q. Please describe any significant factors that affect the cost experienced by the Company in administering its line clearance program.

A. The costs experienced by UPPCO to clear its rights-of-way have increased due to several factors. First, as described above, the cost increases are partially due to the higher cost associated with the drastic increase in tree mortality of off right-of-way trees, which UPPCO refers to as “hazard” or “danger” trees. This scenario requires that the contractor incur increased travel expense in order to investigate both customer and company tree removal requests that occur both in and out of the planned cycle trim areas in order to determine the severity of the situation, the impact to the system, public safety, and the increased risk of fire danger. These processes often require additional negotiation with customers and landowners to obtain permission to cut these danger trees, and in some instances, to remove the associated debris caused by their removal. As a result, the line clearance expenses are projected to increase annually.

Furthermore, the sharp increase in fuel prices over the last several years has caused additional price increases in contractor expenses due to the vast amount of service territory that needs to be traversed to accomplish the annual line clearance miles to remain on-cycle. To help manage this and provide appropriate transparency in this specific cost area, UPPCO has initiated a Diesel Fuel Escalation Policy to help provide a mechanism whereby a positive or negative adjustment to the contract base rate will be implemented, which is tied to set values and benchmarked against published values for the "Retail On-Highway Diesel Prices" in the Midwest region, as published on the U.S. Energy Information Administration website. This is intended to keep any contractor price increase tied to fuel prices from being lost in contractor base rates, or not addressed at all, jeopardizing the contractor's viability of operations, while also automatically reducing UPPCO costs as fuel prices decrease.

Q. Please describe the actions taken by UPPCO to maximize the cost effectiveness and quality of its line clearance program.

A. In addition to the information provided above, UPPCO utilizes standard electric utility line clearance practices in its line clearance specifications. In an effort to maximize the cost effectiveness of the Company's line clearance program, UPPCO relies upon two qualified utility line clearance contractors. This provides opportunity to maintain competitive pricing when soliciting pricing quotes to compare production and pricing performance over a variety of service locations, right-of-way, geographic and environmental conditions, to help leverage this information to achieve a performance-based assignment of the various cycle project areas comprising the Company's 6-year line clearance cycle.

Q. Describe UPPCO's Overhead Inspection Program.

A. UPPCO implements a comprehensive overhead facilities inspection and treatment program. Replacement of poles in poor condition and the treating of ground lines on otherwise sound poles eliminates potential issues before they occur. UPPCO's overhead inspection includes the identification of potential National Electric Safety Code ("NESC") clearance issues. Through the 12-year inspection cycle, UPPCO reviews all poles that UPPCO has facilities attached, including foreign-owned poles, and not only those that are UPPCO-owned. Some items are identified and repaired during the inspection process, such as pole treatment at the ground line, repairing grounds, and installing guy markers, while other identified "danger and reject" poles are scheduled for replacement within a year after the inspection results are received. From 2019 to 2023, an average of 1.5% of the inspected poles were classified as danger or reject poles. This percentage has been generally trending downward as a result of UPPCO's continued pole inspection practices over the years. A record of UPPCO's pole inspections is evidenced in Exhibit A-26 (JRR-7), 2019 – 2023 Pole Inspection History. As seen in this table, the

5-year average cost for the professional overhead system inspection and pole treatment was approximately $175,666 per year or roughly $29 per pole. The overhead inspection program is an on-going maintenance activity, which needs to be continued.

Q. Describe UPPCO's Underground Inspection Program.

A. UPPCO implements an underground inspection program to identify equipment in poor condition, undermined or tilting equipment, and safety issues – before these issues trigger outages. This program entails performing visual inspections of the physical components of the existing underground system on a 6-year cycle. Some items are identified and repaired during the inspection process, such as treating for ants, clearing vegetation, re-leveling, filling gaps in the ground surface, and painting. UPPCO also inspects all newly installed underground facilities during the next construction season after the facilities were put in the ground. A record of UPPCO's underground inspection history is evidenced in Exhibit A-27 (JRR-8), 2019 – 2023 Underground Inspection History. As seen in this table, the 5-year average cost for the professional underground system inspection was approximately $70,308 or roughly $51 per cabinet. Additionally, an average of 113 cabinets were refinished over this period, extending the life of these assets, at a cost of $ 38,536, or roughly $341 per cabinet. The underground inspection program is an on-going maintenance activity that needs to be continued.

Q. Describe UPPCO's Existing Underground Cable Replacement Plan.

A. As mentioned earlier in my testimony, much of UPPCO's underground cable was installed in the 1970s with 175 mil insulation and a bare concentric neutral, which is more prone to faults. UPPCO has test equipment to locate failed underground cable. For radial lines, repairs are made to restore service. If the line is looped, then often times the crew will switch the feed to restore power and leave the failed section of cable out of service. This provides time for Engineering to review the system and determine if the cable section or multiple sections should be replaced, rather than repaired, based on age of the cable and the number of previous failures. UPPCO anticipates replacement of underground cables due to failure and has a budget item to allow for these replacements during the course of the year, thereby providing flexibility to perform opportune cable replacements with a short turnaround time improving the reliability of the system serving those customers.

Q. Describe the Rerouting of Overground to Underground ("strategic undergounding") program.

A. Selective rerouting of overhead lines to underground in areas with a high tree density, prone to frequent tree/storm related outages, and/or limited accessibility is another manner in which to improve system reliability. These projects are capital intensive and therefore only the worst areas are targeted for rerouting. This is a capital expenditure requiring budget funding and prioritization.

Q. Does undergrounding increase system reliability?

A. Yes. UPPCO's OMS tracks causes and devices in outage data, including events involving underground distribution equipment failures. Exhibit A-28 (JRR-9), Underground Outage History, captures the number and impact of underground related events. UPPCO experiences very few underground dig-ins and equipment failures, such as padmount transformer and underground cable failures. The data in Exhibit A-28, Underground Outage History, includes events that *involve*, or serve, underground facilities. Some of these events involve overhead facilities that feed the underground system, such as an animal causing the riser fuse to operate or an arrester failure on the riser. The purpose of this Exhibit is to demonstrate that, even including events that are not strictly caused by failure of UPPCO's underground system, the impact to UPPCO's customers is an order of magnitude less than all other events in terms of SAIDI, SAIFI, and the number of customers affected. For all outage events, excluding transmission-caused, over the period of 2019-2023, UPPCO experienced nearly 10,000 events affecting more than half a million customers over the 5-year period customers resulting in a SAIDI of 2,227 minutes and a SAIFI of 9.2 events. Outages involving underground facilities accounted for only 199 of those events affecting 716 customers resulting in a SAIDI of 2.l minutes and a SAIFI of 0.01 events. So, while including events that involved underground facilities still only comprised 5% of total outage events, those events affected less than ½ of 1% of all customers who experienced outages over the 5-year period and those events resulted in less than 5 SAIDI minutes of the 2,227 total SAIDI minutes affecting all customers. Thus, the data indicates reliability is significantly improved for customers served by underground systems compared to those served by overhead.

Q. Does undergrounding decrease maintenance costs?

A. Yes. As mentioned previously, approximately 73% of UPPCO's 4,500 total electric line miles are configured as overhead conductor and the remaining 27% of the total line miles as underground. Exhibit A-29 (JRR-10), Historical Maintenance Costs, documents UPPCO's overhead ("OH") and underground ("UG") maintenance costs from 2019-2023. The overhead and underground miles are a snapshot in time from UPPCO's GIS system. Data for 2020 was not found and therefore was simply shown as an average of 2019 and 2021 line miles. The data indicate UPPCO's average underground maintenance cost for calendar years 2019 through 2023 was only 8% of UPPCO's total cost to maintain the distribution systems, but more significantly on a per mile basis, underground maintenance averaged only $509 per mile compared to overhead at about $2,119 per mile. The maintenance costs described above are attributable to activities such as: trouble calls/callouts, outage/storm restoration, line clearance activity, inspection programs, locating, and asset refurbishment, among others.

Q. Does strategic undergrounding increase customer value?

A. Replacement of overhead lines with underground provides value to UPPCO customers in several ways. As mentioned in reference to Exhibit A-28 above, outages involving underground account for less than 5% of the total number of outages, so customers receive a huge improvement in reliability with underground. In addition, ongoing maintenance costs of underground is significantly reduced as mentioned above. Although it is a major capital investment to convert overhead to underground, for most projects, the investment pays off over time. A list of projects completed since January 1, 2022, are provided in Exhibit A-30 (JRR-11), Overhead to Underground conversion Projects, and details of each project will be discussed later in my testimony. To illustrate the customer value of converting from an overhead system to underground, I will use the GWN 657

Little Lake Road 1-phase OH to UG. This project installed approximately 12,000 ft of new 1-phase underground facilities to replace existing overhead system at a cost of $357,466; therefore, this job cost about $30 per foot. By way of comparison, UPPCO estimates the average cost for a typical 1-phase overhead system hardening project to be about $37 per foot. So a savings of $7 per foot is realized by converting to underground, which equates to an estimated savings of $84,000 for this job. Additionally, based on annual maintenance costs in 2022 and 2023, the average cost to maintain overhead was $2,486 per mile, or 47¢ per foot, versus underground, which was $564 per mile, or 11¢ per foot, for an annual savings of $1,922 per mile, or 36¢ per foot, with underground, so over the 40-year expected life of the project, the operations and maintenance cost savings will be about $173,000 and this value does not account for inflationary increases. Therefore, looking at this project in terms of either capital or maintenance expenditures, there are direct savings to UPPCO customers. Other strategic undergrounding projects have different levels of return based on the length and complexity of the project.

Q. How does strategic undergrounding decrease customer costs?

A. The increased customer value discussed above does not account for other savings, such as the expected reduction in repetitive outage credits to customers, nor does it account for the intrinsic value of customer satisfaction in the decreased number of outages. Much debate has ensued over the cost of outages to customers; however, a definitive and industry-accepted method has yet to be created. Loss of food or medicine, home heating and cooling, temporary lodging, lost revenue to businesses, etc., all are dependent on various factors, such as demography, outage duration, ambient temperature, customer actions, and even customer expectations. That being said, in Case No. U-20629, Citizens Utility Board of Michigan ("CUB") suggested that outages may cost the average customer $3-4 per hour.[1] Although UPPCO does not agree with this unsubstantiated value, reducing the number and duration of outages will certainly reduce outage costs to customers. UPPCO's 5-year Average SAIDI, including MEDs, reported in Exhibit A-23 (JRR-4) was 446 minutes, or 7.4 hours, per customer per year for all outages, but averaged less than 1 min, or 0.016 hours, per customer per year for underground-related events. Assuming a customer cost of $3.50 per hour, each customer would save about $26 per year. So, in the GWN 657 Little Lake Road 1-phase OH to UG example above, the 26 customers would see an outage cost savings of $676 per year for the life of the installed assets, or about $27,000 over 40 years. These are unrealized savings since they are avoided costs as a result of reduced outages, but they do represent another value to customers by strategic undergrounding. Of course, undergrounding projects can vary significantly in cost due to various factors, such as complexity, ground conditions, ROW availability, access, easements, brushing/line clearance, municipal and/or environmental permitting, customers density, and even customer acceptance.

For the reasons discussed above and to reduce overhead system maintenance costs, UPPCO plans to replace more overhead system with underground cable and equipment.

[1] MPSC Case No. U-20629, Comments of the Citizens Utility Board of Michigan, dk no. 63, p 8.

Q. Are overhead lines always replaced with underground lines when poles near the end of their useful lives?

A. No. Replacing poles with taller and stronger poles is also an effective system hardening process. UPPCO has standardized on Class 3 poles for new 3-phase overhead line construction. Not only can the taller height often help to avoid tree-related outages altogether, but the increased strength can also help to prevent the pole from breaking if a tree does fall on the line. Broken poles, especially during storm conditions, take significantly more time to replace than fixing a broken conductor or removing a tree from the line, so installing stronger and taller poles will strengthen the distribution system and improve both the duration and frequency of outages. This is a capital expenditure requiring budget funding and prioritization.

Q. Please describe UPPCO's Shared Facilities program.

A. The purpose of UPPCO's shared facilities program is to ensure that foreign attachments are accounted for and included in pole loading calculations and bring existing facilities up to current NESC standards when new attachments are requested. UPPCO requires an attachment agreement with all potential pole attaching companies. In addition, requests for new attachments must be accompanied by a certified engineering analysis of the existing poles, conductors, and anchor points. These studies are then reviewed by UPPCO, and all NESC clearance violations and pole strength issues must be corrected at the attaching party's expense prior to any new attachments being made. Pole space sharing is a requirement of state and federal law, and UPPCO will continue to improve the overall strength of the distribution system through review of shared facilities attachment requests and the subsequent make-ready work.

Q. Please describe how UPPCO enhances the restoration process.

A. UPPCO's restoration process is enhanced by increasing the ability for crews to identify, locate, and access the outage location, and by increasing the flexibility of the system for the crews to restore service. While these practices don't necessarily eliminate outage events, they make the system more resilient when outages do occur. Several of the practices already mentioned help crews to better access outage locations, such as continuing the line clearance program and rerouting overhead lines to underground.

This program also includes rerouting cross-country lines to road ROWs to make the system more accessible to crews. Early design practice was to run distribution systems via the most direct route to save on cost and effort to get service to outlying areas. Over time, however, access points can be overrun with vegetation, creating obstacles to utility crews in identifying and accessing outage locations and to making necessary repairs. UPPCO sees significant value and places a higher priority on projects that include rerouting overhead off-ROW lines to an on-ROW underground system, which improves reliability and reduces future maintain costs. Additionally, these projects increase accessibility, reduces line clearance requirements, and provides UPPCO's line crew's ability to more quickly patrol the system and locate outage causes more efficiently. These projects are capital-intensive and require planning and budgeting; therefore, these projects are strategically targeted and weighed against other potential reliability improvement projects and prioritized accordingly.

In some cases, the Company may also add switching capability to increase the flexibility of the distribution system. Due to UPPCO's rural service territory, creating networks or loops within the distribution system can be impractical on a large scale due to the nature of long circuits outside of urban areas. Closing a gap, however, in a rural distribution system where pockets of higher customer densities do exist allows crews to open the system as near as possible to the outage, then close a normally open point to restore power to customers that otherwise would have been outaged until the system can be repaired. The practice of switching to partially restore service significantly reduces the duration of the outage and improves SAIDI metrics. These design considerations are taken into account as part of the capital expenditure budget and prioritization process.

Q. Does UPPCO also use technology solutions to harden the distribution system?

A. Yes. Technological solutions are also considered by UPPCO when it is planning for upcoming reliability improvement projects. UPPCO optimizes distribution technology in several forms:

a) Implementation of a robust Outage Management System ("OMS") provides the ability to dispatch outages more quickly to the correct outage location. Additionally, UPPCO implemented Automated Meter Infrastructure ("AMI"), which automatically reports customer outages and sends them to UPPCO's OMS, indicating exactly which customers are experiencing an outage. This improves efficiencies with dispatching resources and aids in diagnosing system issues. UPPCO is currently working with the OMS and AMI vendors to improve the ability to ping meters following crew restorations and better identify customers who may still be experiencing an outage during storm conditions.

b) Reverse-sensing voltage regulators have also been installed in specific locations that can operate in reverse load flow so that they perform properly when switching the distribution system for partial restoration. This eliminates the requirement for field personnel to manually adjust regulators when switching occurs and frees those personnel to address other outages.

c) UPPCO has been reviewing the overcurrent protection plans on all feeders to assure that reclosers are properly set up, and that they coordinate with other line devices back to the substation. In some cases, overcurrent protection equipment is replaced with newer technology, which coordinates better with other devices on the system. Feeders that have a history of multiple device operations are prioritized first.

d) UPPCO has considered Distribution Automation ("DA") projects, but due to UPPCO's mostly rural service territory, there are not a lot of areas to effectively implement DA. When evaluating projects to improve reliability, however, UPPCO does include possible consideration of DA. UPPCO installed a partial DA project at a very remote substation fed by a radial transmission line. In this case, the line crew must travel a long distance to the substation to isolate and switch to a back-up feeder. UPPCO added SCADA-controlled switches to tie the feeders together to the back-up distribution source. Although it is not automatic, it reduces outage response from a couple hours to only a few minutes for transmission-related outage events.

Capital Expenditure Decision Criterion

Q. Please identify UPPCO's primary capital decision criterion as it relates to selecting distribution system hardening projects.

A. For those storm hardening practices which I have described which require capital investments to improve reliability, UPPCO uses the following decision criterion to prioritize its capital projects:

1. IEEE Indices (SAIDI, SAIFI, and CAIDI) and the number of outages per feeder
2. Worst Feeder Ranking
3. Multiple Device Operations
4. Field Crew Experience
5. Inspection Results

Q. Please describe these decision criteria in greater detail.

A. The following provides additional background on each of the decision criterion:

1. IEEE Indices: As mentioned in the Reliability Metrics section above, the IEEE reliability indices are typically used to compare performance among utilities. This data, however, can also be used internally to compare performance among different districts, feeders, or even down to the device level.
   UPPCO's methodology to analyze where to invest in reliability improvement or storm hardening is partly based on a ranking of UPPCO's feeders. For purposes of

ranking UPPCO's worst feeders, the IEEE indices are used as well as the number of outages per feeder.

2. Worst Feeder Ranking: An analysis of the reliability indices by individual feeder, or circuit, considers the effect of outages on a specific feeder not only as related to the average UPPCO customer, but also as it relates to the geographic region of where that feeder is routed. UPPCO typically reviews the 3-year outage history for the whole company to help prioritize capital improvements by feeder, although at times the 5-year and 2-year outage histories are also used to best determine where the biggest reliability improvements are warranted. A point system is used on each of the four measures (SAIDI, SAIFI, CAIDI, and # of outage events) with the worst feeder in each category getting the top ranking of #1 worst feeder. UPPCO has about 100 feeders in the 5-year data set, so the worst feeder in each category is assigned 1 point and the best feeder assigned 100 points. The points are added for each of the four measures, and the feeder with the lest number of points is considered the worst reliable overall.

3. Multiple Device Operations: Another factor that is used in determining where to target distribution reliability and age/condition improvement projects is the number of device operations. Since UPPCO's feeders are inherently large electrical circuits covering an average of over 64 line-miles per feeder and 20% of the most rural feeders being over 100 miles in total circuit length, no one project can improve an entire feeder's reliability. The multiple device operations metric can therefore pinpoint where reliability improvement work is needed on a specific feeder.

4. Field Crew Experience: Line personnel are quite familiar with outage-prone areas, so crews are frequently interviewed, so that their operational experience can be used to help pinpoint areas where targeted capital expenditures can best improve system reliability.
5. Inspections: UPPCO also considers other ongoing maintenance activities, such as annual overhead line inspections. For example, if several poles along a line require replacement due to the inspection results, UPPCO may consider rerouting the line underground, or replacing with larger poles instead of a like-for-like replacement.

Q. Please explain any other exhibits you are sponsoring that detail aspects of the Company's projected capital expenditures.

A. I am co-sponsoring Exhibit A-7, Schedule B5.4 (JRR/DJG-1) which is the Proposed Distribution & Substation CAPEX by Business Driver and sponsoring Exhibit A-21 (JRR-3) UPPCO Distribution CAPEX. In Exhibit A-7, Schedule B5.4, I project a slight increase in capital expense from the historical period, through the bridge period, and into the projected test year related to improving reliability and new equipment or equipment upgrade at the substation level. Likewise, A-21 shows similar increases for the same reasons.

Customer Value Determination

Q. Please describe UPPCO's customer value determination on its distribution system capital spending projects.

A. To provide a better customer experience and to strive towards the State's goals to reduce outages and improve reliability will require additional capital investment for storm hardening. Due to UPPCO's low customer density and miles of line per customer, it is difficult to significantly improve reliability and resiliency of UPPCO's system at current investment levels.

UPPCO's distribution projects have historically had a focus on ensuring MPSC compliance for distribution system adequacy, safety, and proper voltage levels, with varying scope due to the dynamic nature of system integrity and the distribution system load profile driven by customer demographics over time. With increasing customer expectations along with the updated requirements of the MPSC's revised Service Quality and Reliability Standards for Electric Distribution Systems, more emphasis is being placed on reliability improvement and faster storm restoration. UPPCO therefore finds it necessary to increase the levels of capital spending on reliability projects to improve service to customers.

In addition to projects necessary for safety, compliance, voltage, or system loading issues, the selection of specific reliability-based projects is determined using a combination of (1) the severity of the outage data at a given location, (2) the age and condition of the existing distribution facilities, (3) the availability of capital resources, (4) the number of customers benefiting, and (5) logistical considerations such as design complexity, constraints due to access, right of way, easements, permitting, and weather, as well as with material, labor, and contractor resource availability.

Reliability and age/condition often overlap in outage statistics; therefore, UPPCO uses the data to help indicate the best locations to direct capital improvements. Capital budget dollars are then allocated to the specific locations that have the greatest need for distribution reinforcement.

UPPCO's storm hardening efforts are a systematic and efficient approach designed to improve reliability over time. Targeted projects on UPPCO's worst feeders will improve customer satisfaction, reduce the number and duration of outages, make UPPCO's distribution more resilient during storms, and move UPPCO closer to the State's goals to reduce the number and duration of outages and improve the customer experience.

Q. Please describe UPPCO's plan for managing its distribution assets, and identify key projects that help provide a safe, reliable, efficient electric system for its customers.

A. For typical distribution reinforcement projects, UPPCO has a 5-year planning horizon. Each year upcoming project designs are reviewed, and potential issues, such as easements, permits, resource availability, landscape, and customer demographic changes, are reviewed prior to design finalization. If any issues arise during the review process, options are considered which could still provide similar benefits. Project scopes may be adjusted based on this review, or other higher priority projects may have been uncovered since the last review, and these projects may be reprioritized within a budget year, or even within the 5-year planning horizon as system conditions evolve from year to year.

Report on Overhead to Underground Projects Completed Since January 1, 2022 (Case No. U-21286 Rate Case Settlement Agreement)

Q. Please respond to the U-21286 Rate Case Settlement 9.i.(1) which reads, "In its next rate case, the Company shall include: (1) A report on all of the overhead to underground projects completed since January 1, 2022 that includes the following information for each project that are greater than $50,000: (i) total capital expenditures to complete the project, (ii) number of miles undergrounded, (iii) number of customers affected, (iv) SAIDI and SAIFI reliability benefits by circuit. The report shall also describe how the projects' costs and benefits compare to tree trimming and grid hardening and include a description of how undergrounding may be included in a distribution plan, and a discussion of safety and reliability. This report will compare the average O&M for underground and overhead facilities."

A. In Exhibit A-30, 2022 – 2023 Overhead to Underground Projects, UPPCO lists all distribution reliability improvement projects involving conversion of overhead facilities to underground greater than $50,000 in capital expenditures completed since January 1, 2022. For each project UPPCO provides the capital expenditures, line miles of underground installed, the number of customers benefitted by the project, and the expected SAIDI and SAIFI improvement on the circuit. Note, miles of underground installed may be slightly different than the miles of overhead removed due to route changes from the existing overhead line, abandoned facilities removed, or the like. SAIDI and SAIFI are complex metrics to report due to the relatively small scope of the projects with respect to UPPCO's entire distribution system.

Q. Please describe UPPCO's methodology to determine SAIDI and SAIFI reliability benefits by circuit.

A. The scope of UPPCO's typical overhead to underground conversion projects range from less than one mile to up to a couple of miles. UPPCO's total system consists of about 4,500 line-miles. The Settlement Agreement asked for the SAIDI and SAIFI benefits by circuit, however, the reliability improvements realized by overhead to underground conversion projects will appear quite small on a "system" basis due to the small scope of these projects size compared to the total line miles of UPPCO's distribution system. To determine the SAIDI and SAIFI improvement by circuit, UPPCO calculated the "Circuit" SAIDI and SAIFI based on the number of customers on the circuit rather than on UPPCO's total customer base. These will be referred to as "cSAIDI" and "cSAIFI." Since SAIDI and SAIFI, as well as cSAIDI and cSAIFI, vary significantly due to weather conditions from year to year, UPPCO used the cumulative metrics for the past 5 years, 2019 to 2023, to determine the expected reliability improvement as a percentage of the reliability metrics before and after completion of the conversion projects. The percentage shown in Exhibit A-30 reflects the estimated reduction in cSAIDI and cSAIFI if UPPCO had experienced the exact same outages as the previous 5 years but with the overhead to underground conversion in place over the entire 5-year period. Each project has different completion and cutover dates from the old overhead system to the new underground system, therefore, reliability benefits of projects completed within 2022 or 2023 calendar years is encompassed within the historical data. In other words, some of the reliability improvements were already realized within the historical data, and therefore, the percentages shown in the Exhibit may be slightly low. However, for consistency among these projects, UPPCO finds the 2019-2023 historical data to be acceptable for the purpose of calculating the cSAIDI and cSAIFI improvements.

Q. Please describe the capital spend difference between 2022 and 2023 overhead to underground conversion projects in Exhibit A-30.

A. Construction for large capital projects sometimes carries over from year to year. Many of the 2022 budgeted capex projects were large in scope and were not completed until 2023.

Q. Please explain why there were not more overhead to underground conversion projects in Exhibit A-30 which carried over from 2021 and completed in 2022.

A. There are several reasons why there were not many overhead to underground projects that were started in 2021 and completed in 2022: (1) In 2021, nearly all overhead to underground conversion projects were completed within the calendar year with the exception of the Summer Homes project, which is one of the projects listed in Exhibit A-30, (2) UPPCO had a substation expansion planned in 2021 that necessitated the construction of new mainline underground feeders to support the substation project, which consumed approximately $1M of the 2021 budget, (3) Several small underground 1-phase aged/failing cable <u>replacement</u> projects were completed, and (4) UPPCO shifted some budget dollars to overhead projects due to industry-wide shortages of underground materials following the outbreak of COVID-19, specifically cable, junction enclosures, and padmount transformers. The shortages increased lead times on numerous electric utility components from weeks to a year or more, so underground materials were not readily available.

Q. Please describe how the projects' costs and benefits compare to tree trimming and grid hardening.

A. As mentioned earlier in my testimony, UPPCO's Distribution Engineering group analyzes historical outage data to determine UPPCO's worst feeders in terms of reliability and then targets the segments of those circuits where reliability improvement projects can have the biggest impact. In many cases, the existing overhead line that is targeted for improvement is not just rebuilt in place as underground, but it is relocated to the road ROW to achieve better access for future maintenance or for line extensions. As mentioned previously in my testimony, strategic undergrounding is one method to harden UPPCO's distribution system. Another method is to rebuild an existing overhead line with higher class and taller poles and reconductoring the line to current conductor material and spacing standards. However, hardening the overhead system requires continued line clearance effort and overhead maintenance expenditures. UPPCO uses design software to estimate distribution project costs. Using this tool, UPPCO created by-foot rates for performing rough estimates for future projects and budgeting purposes. The by-foot estimates are based on typical job parameters, material, labor, equipment, and contract costs. These estimates do not include permitting, easements, outside engineering, or special equipment. The estimated costs for overhead projects include initial line clearance and cycle clearance for the expected life of the project as well as the annual increased maintenance cost of overhead versus underground as discussed previously. Line clearance costs are typically required for overhead projects but can be quite a variable component due to the last trim, possible rerouting, new pole heights, etc. Therefore, for the purpose of these high-level estimates, UPPCO uses the historical line clearance cycle-trimming cost reported in Exhibit A-13. For 2023, line clearance was $3,206,845 for 377 miles resulting or $8,506 per mile. UPPCO feels this is a reasonable line clearance estimate for overhead projects. Using this methodology UPPCO calculated the current overhead “hardening” project to have a total cost of approximately $64 per foot for 1-phase and $95 per foot for 3-phase. Underground projects are more complex and variable than overhead due to surface and underground conditions, so UPPCO created a range of by-foot rates for strategic undergrounding projects. Therefore, these projects are expected to be within a range of $38-35 for 1-phase and $85-109 for 3-phase.

Q. Please describe how undergrounding may be included in a distribution plan.

A. UPPCO is currently developing its Distribution Plan in response to the U-21286 Rate Case Settlement 9.h. and strategic undergrounding will comprise a significant portion of UPPCO’s reliability improvement planning process within the Distribution Plan just as it has been discussed throughout my testimony above.

Q. Please describe the safety and reliability benefits of overhead to underground projects.

A. I have described the reliability benefits of overhead to underground projects in detail earlier in my testimony and I will discuss the intent and benefits of individual overhead to underground projects completed since January 1, 2022, later in my testimony below.

Regarding safety, in general, UPPCO experiences very few safety events involving its underground system.

For the 5-year period of 2019-2023, nearly 540,000 customers experienced outages, and of those, less than 2,000 customers were affected by outages involving underground as shown in Exhibit A-28. Events caused by the public, such as vehicle accidents and dig-ins, accounted for outages to about 31,000 UPPCO customers as shown in Exhibit A-25. Of those, only 55 customers experienced outages due to dig-ins into UPPCO's underground system. Vehicle accidents accounted for nearly 25,500 customer outages, and of those, only 261 involved underground conductor or padmount transformers. These data generally indicate underground infrastructure is inherently safer and more reliable than overhead due to the fact that there is significantly less exposure to the public and the elements. Furthermore, UPPCO responds to MISSDIG locate requests promptly to mitigate the risk of inadvertent contact with buried electrical infrastructure and routinely issues public safety messaging through various media sources to assist the public in identifying and mitigating the hazards of coming into contact with electrical infrastructure.

Q. Please compare the average O&M for underground and overhead facilities.

A. As discussed previously in my testimony, UPPCO provided Exhibit A-29 which indicates UPPCO's total maintenance expenses from 2019 to 2023.

Now I will describe each of the overhead to underground projects greater than $50,000 completed since January 1, 2022.

Q. Please describe the overhead to underground project, Bay 515 P Rd 3-phase OH to UG (Terrace Bay) project.

A. The P Rd 3-phase overhead to underground project in Wells Township began as a request from the Terrace Bay Motel for building expansion and beautification. The customer-requested portion of the project consisted of approximately 1,050 ft of new 3-phase and 700 feet of new 1-phase underground cable and was paid for by the customer for the overhead facilities relocation. UPPCO's portion of this project was an extension of the customer-requested portion and converted an additional 575 ft of 3-phase overhead line to underground north of the motel because UPPCO customers had experienced numerous outages over the years due to wind coming off the lake and deterioration of the overhead line due to the highway road salt. There are 308 customers served by the sections of line placed underground for this project along with the customer-requested portion. However, since this is feeder mainline and there are no other overcurrent protection devices from this project area back to the substation, it benefits all 1,069 customers served by the feeder.

Q. Please describe the overhead to underground project, MUN 617 Summer Homes 1-phase OH to UG.

A. The scope of the Summer Homes 1-phase overhead to underground project included the installation of approximately 2.25 miles of new 1/0 underground cable routed along AuTrain Forest Lake Rd, Buckbay Rd (aka Federal Forest Road 2276) and Campground Rd to eliminate an overhead water crossing and overhead facilities along an inaccessible section of overhead line serving 29 customers. Due to the historically poor reliability of this area, a section of line was replaced in 2018. This project continued undergrounding the worst sections of the overhead system and was completed in early 2022. This area sustained 3 outages since January 1, 2019, with an average duration of 10.5 hours per event affecting all the customers on this tap. The entire section of primary line serving these 29 customers is now 100% underground.

Q. Please describe the overhead to underground project, CHA 616 County Line Rd 1-phase OH to UG.

A. The scope of the County Line Rd project included replacement of approximately 1,800 ft of copperweld overhead conductor and 8 aged poles with 1,550 ft of new 1/0 underground cable and about 250 ft of new underground 350 KCM secondary triplex cable. This project was completed in conjunction with a customer line extension for a new service. This is a swampy area routed in US Forest Service property, and although these customers have not endured any outage events affecting this portion of line over the past 5 years, this line segment is the furthest point west on the Chatham 616 circuit, 31 road miles from the Munising service center.

Q. Please describe the overhead to underground project, GWN 657 Little Lake Road 1-phase OH to UG.

A. The scope of the Little Lake Rd 1-phase OH to UG project included burial of approximately 12,000 of new underground cable and removal of 33 overhead poles and approximately 9,000 ft of 1-phase and neutral copperweld conductor along with approximately 1,000 ft of overhead secondary cable. Much of the old overhead system was routed off the road right-of-way in a heavily wooded area. Sub-projects to this project included conversion of several customer services from overhead to underground.

From 2019 through 2023, this single-phase tap line was outaged 17 times affecting approximately 27 customers per event. This area is no longer susceptible to vegetation issues which improves the safety and reliability.

Q. Please describe the overhead to underground project, FRY 2733 Shag Lake 2-phase OH to UG Part 1.

A. The scope of the Shag Lake 2-phase OH to UG Part 1 project included burial of approximately 5,000 ft of new 2-phase 1/0 underground cable extending west from County Road 557 along Shag Lake Dr and removal of 15 poles and approximately 2,750 ft of 2-phase and neutral 2ACSR conductor along with approximately 500 ft of overhead secondary cable routed cross-country off-ROW. This job also included installation of new 1-phase poles and overhead conductor to extend the 2-phase system about 500ft along Shag Lake Dr to create a more optimal overcurrent protection scheme and open points to reduce the number of customers affected in various outage scenarios. Additionally, about 1,100 ft of 3-phase underground cable was installed to close a gap along County Road 557 between two sections of the circuit, which provides a means to loop a portion of the system to perform partial restorations and also allows for future 3-phase extensions along a county road.

This project will directly benefit the 285 customers served by the Shag Lake Drive tap and indirectly benefit at least 84 customers served off of County Road 557 and Knudsen Rd due to the newly created switching corridor created by closing the gap on County Road 557. The circuit SAIDI and SAIFI improvements indicated in Exhibit A-30 (JRR-

11) are based only on the 285 customers directly served by the overhead to underground project.

Q. Please describe the overhead to underground project, BNM 1237 Lake Bacon Reroute 3-ph OH to UG.

A. The scope of the Lake Bacon reroute project included removal of an existing 3-phase overhead line consisting of several poles identified as rejects through UPPCO's overhead inspection program, which were located in a wooded area with poor accessibility and crossed over Lake Bacon. This line provided a tie between Barnum feeders 1205 and 1237, which is critical loop within the City for 650 residential and commercial customers. This project removed about 2,350 ft of overhead line and installed about 2,000 ft of new 3-phase and 160 ft of new 1-phase underground cable along road ROW. Since there were no customers directly served from the section of overhead that was replaced with underground there is no analytical means to indicate SAIDI and SAIFI improvements. Additionally, a tie line previously existed so it would be speculative to state that the new underground tie line could have been used any differently for partial restorations in the past 5 years than the previous overhead tie line. However, this project does ensure a reliable loop to customers served from both feeders within the City of Ishpeming which can be used for partial restorations for future outage events on either circuit's mainline. The direct and immediate benefit to the 650 customers north of US 41 is apparent with recent MDOT work to construct a new round-about on US 41 where this new section of underground is currently serving those 650 customers so the line could be de-energized and opened to accommodate MDOT's construction.

Q. Please describe the overhead to underground project, BNM 1237 US 41 Reroute 3-ph OH to UG.

A. The scope was to replace a crossing over US 41 and extend 3-phase underground on the north side of US 41 in the City of Ishpeming. This project eliminated a 210-ft section of overhead line crossing 5 lanes of traffic over US 41 and installed a new 3-phase underground crossing along with new 3-phase underground tie lines to the existing overhead system on the north side of US 41. Additionally, this project installed approximately 2,000 ft of new 3-phase underground along the north side of US 41 which replaced an inaccessible section of overhead line located off-road ROW between an active railroad track and buildings that this section of line served. There were no outages over the past five years on this section of line, therefore, SAIDI and SAIFI benefits cannot be quantified. The direct benefit of this project will be to the 35 customers fed from this tap line in avoided future lengthy outages that could have occurred on this inaccessible section of line, but it also provides a reliable mainline feed for the customers on the north side of US 41.

Q. Please describe the overhead to underground project, KIS 1275 Tie to GWN 657 3-ph OH to UG Part 2.

A. The scope of the KIS 1275 to GWN 657 Tie Part 2 was to continue replacement of off-road ROW 3-phase overhead line to 3-phase underground routed along the road ROW. Part 1 of this project established a 3-phase tie point from the Gwinn Little Lake circuit serving 1,073 customers to the KI Sawyer 1273 circuit serving 1,628 customers. Part 1 replaced sections of 1-phase and 3-phase overhead with approximately 2 miles of new 3-

phase underground 4/0 cable. Part 2 converted another 2.2 miles of off-road ROW overhead line with the installation of approximately 12,000 ft of new 3-phase and 1-phase underground cable. The old OH lines were inaccessible areas and were in poor condition. Furthermore, the customers served from the KI Sawyer substation are fed from an American Transmission Company ("ATC") radial transmission line. An immediate benefit of Part 1 of this project was observed when ATC required an outage to the radial transmission line to replace a several structures that could not be replaced under energized conditions. Part 2 upgraded the capacity and reliability of this tie between KIS 1275 and GWN 657. Customers directly served by this section of line experienced 9 outages over the past 5 years for which the cSAIDI and cSAIFI improvements were based.

Q. Please describe the overhead to underground project, KWN 927 3-ph Mainline UG.

A. The scope of the KWN 927 3-ph Mainline UG project was to reroute existing overhead mainline to new 3-phase underground cable approximately 2.7 miles along the Gratiot Lake Road from the Keweenaw Substation to US 41. The Keweenaw Substation is located 35 miles from the Houghton Service Center and travel time to begin patrolling often exceeds 60 minutes due to traffic and road conditions. Also, the existing route of the overhead feeder traverses a corridor with vegetation on each side resulting in difficult accessibility and patrolling. Due to the limited accessibility and size of the trees along this corridor, overhead options such as increasing pole height, strengthening the overhead conductor or increasing the size of the tree corridor would not ensure a safer or more reliable system. This project moved 1,205 customers of 1,238 on the feeder onto the new underground system constructed within the road ROW. This section of line has experienced 4 outages over the past 5 years affecting all the customers served by the feeder. By converting to an underground system, the 3-phase mainline exiting the substation is no longer susceptible to vegetation issues which improves the safety and performance of this remote feeder.

Q. Please describe the overhead to underground project, M38 747 Pelkie 2-ph OH to 3-ph UG Part 1.

A. The scope of this multi-part project was to replace existing overhead system with underground in an area remote from the UPPCO Service Center. There are 356 customers served from this section of line, which are located about 35 miles from the Service Center. The existing facilities consisted of 2-phase copper wire that had accessibility issues and had become brittle with age and existing poles installed in 1977 and 1978, which is beyond the typical expected 40-year life of a utility pole. Additionally, the 2-phase construction was load unbalanced, which limited the ability to maintain voltage and confine outage events to smaller groups of customers. To improve feeder performance, the brittle conductor was beyond end of life and necessitated replacement. The existing 2-phase was underbuilt on a double-circuit with hydro generation facilities that further complicated the ability to quickly restore power following outages. Rather than rebuilding overhead 3-phase underneath the existing hydro line, a new 3-phase underground system was designed and installed, which improves safety and allows for more efficient restoration processes by increasing separation between the hydro and distribution facilities. Furthermore, adding the third phase helps better balance the load on the feeder as well as to set up the distribution system for future reliability improvements downline.

Q. Please describe the overhead to underground project, OSC 717 Relocate Mohawk 3-ph OH to UG Parts 1 and 2.

A. The OSC 717 Relocate Mohawk 3-ph OH to UG project was created to replace and reroute existing overhead facilities to underground to the US 41 ROW.

The overhead feeder into Mohawk, MI, leaves the road right of way for 1.25 miles between Ahmeek and Mohawk exposing 548 customers to extended outages due to vegetation and difficult accessibility for crews to restore power. Relocating the facilities from this cross-country section out to the highway results in a more reliable system by improving access and the ability to patrol the line. By converting to underground, the system will have less vegetation and vehicle exposure than if it were rebuilt as an overhead line along the highway. Additionally, this part of the project is on a curve in the highway and placing it underground it improves crew and public safety. Due to resource availability, this project was spread across multiple years. Part 1 installed approximately 3,000 ft of new 3-phase and 850 ft of 1-phase of underground cable, then converted 36 of the 548 customers to the new underground.

Mohawk 3-ph OH to UG Part 2 installed approximately 1,600 ft of new 3-phase and 300 ft of new 1-phase underground cable to continue the mainline along US 41 into the town of Mohawk and to tie-in an existing 1-phase customer.

Mohawk Part 3 will reconstruct existing 1-phase overhead to 3-phase through the town of Mohawk and to transfer the remaining 512 customers onto the mainline system. Therefore, the full benefit of the Mohawk underground project won't be realized until all three Parts are completed, which is planned for 2024.

System Hardening & Reliability Projects 2024 - 2025

Q. Please respond to U-21286 Rate Case Settlement section 9.i.(2) which reads, "For each strategic undergrounding project proposed in the next rate case that is greater than $50,000, the Company will provide an analysis of how the benefit/cost of the proposed undergrounding project compares to that of other solutions the Company is currently employing to enhance the reliability of the distribution system. This includes, but is not limited to, benefit/cost comparisons of strategic undergrounding alongside the benefit/cost of employing grid hardening, tree trimming, and other solutions."

A. The reliability benefits and costs of underground compared to overhead has been detailed throughout my testimony. For cost comparisons, UPPCO utilizes distribution design software to calculate estimated project costs. Earlier in my testimony in the section regarding the 2022 and 2023 overhead to underground projects, the same question was asked (refer to page 32). UPPCO creates and updates by-foot rates for typical, standard, overhead and underground projects which can be used for high-level estimating and for cost comparisons between projects. However, these by-foot rates can be quite variable due to actual surface and underground conditions and System Hardening and Reliability

Projects ("SHARP") are not strictly chosen and prioritized based on cost; they are also designed with the intent to improve crew accessibility, provide new switching corridors for the crew to perform stepped restorations, replace infrastructure nearing its useful end of life, maintain the system in a safe state, or increase capacity for load growth. Projects with these objectives will inherently improve safety and reliability due to new construction spacing standards, increasing switching corridors, and reducing crew patrol time, but are difficult to quantify in terms of SAIDI and SAIFI metrics or cost benefits. As mentioned previously, customers will benefit somewhat monetarily with reduced outages, but they will also experience intrinsic value that cannot be measured. The remainder of my direct testimony will describe each SHARP project planned for 2024 and 2025 that is anticipated to cost more than $50,000 and address the related benefits and any considered alternatives.

Q. Please describe Exhibit A-31 (JRR-12) and identify both the project driver classification system and the distribution capital expenditure projects that UPPCO has identified, as incremental to its sustaining and/or base capital level of spending.

A. UPPCO is planning to implement the projects as evidenced in Exhibit A-31, 2024 – 2025 System Hardening and Reliability Projects, which lists each SHARP project planned for 2024 and 2025, including each project's estimated cost. The purpose and anticipated benefits for each project are summarized in a column listing the Company's project classification. UPPCO's project classification system is as follows: R – Reliability/Storm Hardening; A – Age & Condition; S – Safety; C – Compliance/Voltage; and L –

Load/Capacity. The identification of these projects ultimately informs UPPCO's improved reliability and load growth component of the Company's distribution CAPEX plan.

I will now describe each of the SHARP projects listed in Exhibit A-31.

Q. Please describe SHARP project, M38 747 Copper replacement on M38 Part 2.

A. This feeder is the 9th worst performing feeder based on outage data from 2020-2022. The Alston Nisula area was the biggest contributor to this feeder's poor performance, which consists of 356 customers, and has experienced long outages over this period. UPPCO facilities serving these customers consist of aged poles and old copper wire with areas that are difficult to access and repair due to being located on the far edge of the road ROW. Additionally, the existing system is situated as the lower circuit of a double-circuit line with a hydro-generation line above it that creates additional complications during outage restoration. Further, the existing line is 2-phase, which does not allow opportunity to balance load to improve the voltage profile and limit outages to smaller groups of customers. UPPCO began to convert the 2-phase copper overhead system along M38 to 3-phase underground cable in 2022. Part 2 of this project will continue converting the overhead 2- phase line to 3-phase underground for an additional 9,000 ft to the Prickett Dam Road.

Q. Please describe SHARP project, KWN 927 Copper Harbor to Mtn. Lodge rebuild.

A. This feeder is the 6th worst performing feeder based on outage data from 2020-2022. Extended travel time is needed to reach this area and is prone to vegetation-related outages throughout the length of this feeder. This project impacts 112 customers served at the end of the feeder connecting Copper Harbor to the Keweenaw Mountain Lodge, who experienced repetitive outages between 2020-2022. The existing facilities are old copper wire installed in 1977 that extend along a cross country route with limited access, tall vegetation on both sides of the corridor, and rocky surface and ground conditions. This project will replace the existing aged 3-phase overhead facilities with a combination of new overhead and underground depending on what the ground conditions and terrain allow. The total project length is 1.2 miles and climbs up a steep hill. Grade improvements and new access points to the existing corridor were completed in 2023 to accommodate the construction of this project in 2024.

Q. Please describe SHARP project, OSC 717 Relocate Mohawk to Highway Part 3.

A. This feeder is the 36th worst performing feeder based off outage data from 2020-2022. However, OSC 717 has been prone to long duration outages over the last 10 years. This feeder was UPPCO's 5th worst feeder in 2017 and 19th worst in 2020. UPPCO completed a large CapEx project on this line in 2021, which rerouted about 1¼ miles of cross-country line to the US 41 road ROW, that likely contributed to this feeder's improved reliability metrics. As the feeder continues north and approaches the village of Mohawk, it leaves the road right of way for 1.25 miles exposing 548 customers to extended outages due to vegetation and difficult access. The reliability of this feeder will continue to improve by relocating facilities from this cross-country section to the US 41 ROW to improve access and the ability to patrol during outage restoration. This project is the thirst part of a 3-part project. Part 1 installed of 2,500 ft of new underground completed in 2022. Part 2 installed 1,600 ft of underground cable completed in 2023. Part 3 will rebuild overhead 1-phase to 3-phase through the town of Mohawk, which will tie the new underground to the existing overhead 3-phase system in Mohawk on US 41.

Q. Please describe SHARP project, LIN 3063 Replace copper and establish tie around Sunset Lake.

A. This feeder is the 15th worst performing feeder based on outage data from 2020-2022. The Sunset Lake area has been the biggest contributing factor to the poor performance of this feeder. These 339 customers are served by a mix of underground and old overhead conductor that switches from 2-phase to 1-phase partway around the lake. Much of this system was constructed in the 1970s and is prone to vegetation issues. To decrease the number of outages and improve the restoration time of future outages, this project will replace 7,900 ft of existing #4 ACSR and copper wire with 1/0 ACSR and establish a 2-phase loop around Sunset Lake with an additional 2,700 ft of new 2-phase conductor.

Q. Please describe SHARP project, BARNUM 1231 N. Rose Street.

A. This feeder is the 1st worst performing feeder based on outage data from 2020-2022. There are 17 customers on Rose Street that have experienced many long duration outages complicated by the existing overhead facilities being constructed along customers backyard lot lines. The location of these overhead facilities makes them difficult to access, patrol, and repair. This project will replace 2,200 ft of existing 1-phase overhead with 1/0 underground cable which will reduce vegetation outages and mitigate the maintenance needed on the system.

Q. Please describe SHARP project, BARNUM 1231 Lake Breeze Lane.

A. This feeder is the 1st worst performing feeder based off outage data from 2020-2022. There are 21 customers in the North Basin area that have experienced many long duration outages complicated by the existing overhead facilities routed through a narrow lakeside easement alongside large oak trees. The location of these overhead facilities makes it difficult to access, patrol, and repair. This project will install 5,500 ft of 1-phase 1/0 underground cable along a more accessible route which will reduce vegetation outages and mitigate the maintenance needed on the system.

Q. Please describe SHARP project, BARNUM 1231 Bussone and Marra Drive.

A. This feeder is the 1st worst performing feeder based on outage data from 2020-2022. There are 31 customers in the South Basin area that are susceptible to long duration outages due to difficult access for the existing overhead system. A total of 5,400 ft of 1-phase underground 1/0 cable will be installed to convert and reroute the overhead and eliminate two inaccessible overhead water crossings which will reduce vegetation outages and mitigate the maintenance needed on the system.

Q. Please describe SHARP project, PERCH LAKE 401 Squaw Lake OH to UG.

A. This feeder is the 3rd worst performing feeder based on outage data from 2020-2022. There are 5 customers in the Squaw Lake area that have experienced many long duration outages complicated by access to the existing overhead facilities. The terrain of the existing overhead facilities is rugged and traverses a marsh and 2 lake crossings. This difficult to maintain overhead system will be removed and a total of 6,200 ft of 1/0 underground cable will be installed to reduce vegetation outages and mitigate the maintenance needed on the system.

Q. Please describe SHARP project, DELTA 589 M35 South OH to UG and Loop Tie.

A. This feeder is the 10th worst performing feeder based on outage data from 2020-2022. There are 29 customers along M35 in the Ford River area that have experienced many long duration outages complicated by access to the existing overhead facilities. The existing overhead facilities were constructed in the 1970s and are difficult to access as they extend through cedar swamps. This difficult to maintain overhead system will be removed and rerouted with the installation of 10,500 ft of 1-phase 1/0 underground cable to reduce vegetation outages and mitigate the maintenance needed on the system.

Q. Please describe SHARP project, PERCH LAKE Substation Feeder Exit Relocation.

A. Based on outage data from 2020-2022, PLK 401 is the 3rd worst performing feeder and PLK 403 is the 27th worst. The Perch Lake substation will be rebuilt due to necessary substation maintenance and to improve loss of bay capabilities for the distribution circuits. Feeder exit work will be completed in conjunction with the substation project, which is designed to relocate the feeder exits from the north side to the south-west side of the sub. This project will install new underground feeder exits for both Perch Lake feeders with a tie point between them outside the substation and the overcurrent protection plan will be reviewed and updated as part of this project as well.

Q. Please describe SHARP project, MASONVILLE Substation Feeder Exit Rework.

A. This project will replace and reconfigure the existing substation feeder exits with 4/0 underground cable. The existing exits are nearing capacity under loss of bay scenarios with consideration of future load growth. As part of the feeder exit upgrade, new 3-phase switches will be installed outside the substation to improve switching capability between the feeders. Furthermore, the MSV 987 feeder is underbuilt on an overhead pole line owned by Alger Delta for 8,200 ft 3-phase along a railroad corridor with difficult truck access for maintenance and patrolling, which exposes 610 customers to the potential for extended outage durations. This project will provide for a future project to install underground to fill a gap in the MSV 987 circuit and allow for the removal of the inaccessible sections of overhead.

Q. Please describe SHARP project, BARNUM 1237 US41 Round-about Rework.

A. This feeder is the 33rd worst performing feeder based on outage data from 2020-2022. However, the current configuration of the Barnum 1237 feeder exposes 64 commercial customers, including Bell Hospital, to over 5 miles of system that can be avoided with the creation of a new tie point. This project will create a 3-phase loop and reduce exposure to the Country Village business area and provide a redundant feed into Ishpeming, improving restoration time for 650 customers that are currently on a radial line.

Q. Please describe SHARP project, FORSYTH 2733 Escanaba River UG Cable Replacement.

A. This feeder is the 5th worst performing feeder based on outage data from 2020-2022. A section of this feeder’s underground cable along M35 normally serves 124 customers, but also provides a 3-phase tie to Barnum feeder 1203, is showing signs of reaching the end of life. The existing underground cables were installed in 1980 and experienced a failure in 2023. This project will proactively replace 1,550 ft of 3-phase mainline underground cable before additional failures occur and also will replace a 350-foot overhead river crossing with underground to reduce exposure to weather and animals.

Q. Please describe SHARP project, BARNUM 1231 Rundman Drive.

A. This feeder is the 1st worst performing feeder based on outage data from 2020-2022. There are 5 customers on Rundman Drive in the South Basin area that are susceptible to long duration outages due to vegetation and difficult access to the existing overhead system. The existing 1-phase overhead facilities are constructed along customers' back lot lines and are difficult to access, repair, and patrol. This project will remove and reroute existing 1-phase overhead with 2,585 ft of 1/0 underground cable to reduce vegetation outages and mitigate the maintenance needed on the system.

Q. Please describe SHARP project, BARNUM 1231 Part 1 Sparks Drive.

A. This feeder is the 1st worst performing feeder based on outage data from 2020-2022. There are 40 customers in the North Camp area that have experienced multiple long duration outages due to vegetation that are complicated by difficult access. The existing 1-phase overhead facilities are built through the woods making it difficult to access for patrolling and outage restoration. This project will eliminate 11,00 ft of problematic 1-phase overhead conductor with 14,000 ft of 1/0 underground cable with improved access. This will reduce vegetation outages and mitigate the maintenance needed on the system.

Q. Please describe SHARP project, FORSYTH 2733 Serenity Drive.

A. This feeder is the 5th worst performing feeder based on outage data from 2020-2022. There are 339 customers downstream of the recloser on Serenity Dr that have experienced multiple long duration outages due to the heavily wooded nature of this area. This project converts 8,300 ft of problematic 2-phase overhead conductor to 3-phase 4/0 underground cable. By installing 3-phase this will limit outages to smaller groups of customers and reduce outage impact. This project will reduce vegetation outages and mitigate the maintenance needed on the system.

Q. Please describe SHARP project, FORSYTH 2733 Little Shag Road-South Tap

A. This feeder is the 5th worst performing feeder based on outage data from 2020-2022. There are 51 customers on Little Shag Lake Road that have experienced multiple long duration outages due to the heavily wooded nature of this area. This project eliminates 6,800 ft of 1-phase overhead facilities through a heavily wooded and congested area with many homes in close proximity to each other. This project converts 6,800 of problematic overhead conductor to 1/0 1-phase underground cable. This will reduce vegetation outages and mitigate the maintenance needed on the system.

Q. Please describe SHARP project, PERCH LAKE 401 Part 1 Horseshoe Lake.

A. This feeder is the 3rd worst performing feeder based off outage data from 2020-2022. There are 186 customers in the Horseshoe Lake area that have experienced multiple long duration outages due to the heavily wooded nature of this area. This project eliminates problematic overhead conductor and reroutes it with 4,050 ft of 1-phase 1/0 underground cable with improved access. This will reduce vegetation outages and mitigate the maintenance needed on the system.

Q. Please describe SHARP project, KWN 927 OH-UG conversion US 41.

A. This feeder is the 6^{th} worst performing feeder based on outage data from 2020-2022. Extended travel time is needed to reach this area which is prone to vegetation-caused outages along the entire length of this feeder. The 6,900 ft of overhead conductor along US 41 between Gratiot Lake Road and the Eagle Harbor Crosscut Road is constructed with compact spacing using coated wire and plastic wire ties that are showing signs of reaching the end of useful life. When these ties fail, it cascades across several spans of overhead and extends the outage restoration effort and duration. This section of the feeder is main line that serves 1,205 customers and converting these 3-phase facilities to underground will reduce the vegetation impact and mitigate the maintenance needed on the system.

Q. Please describe SHARP project, ELE distribution tie project “CANAL CROSSING”

A. The Portage Canal underwater crossing cables have been in service for a very long time and are showing signs of nearing the end of useful life. UPPCO records do not indicate the installation date of these cables, but UPPCO believes they were installed at the time the “new” Portage Lake Lift Bridge was constructed in the mid to late 1950s based on an lease agreement from 1956 indicating the cable house and power lines would be moved from their “present location” to a location “west of the proposed new Houghton County bridge” indicating these cables are approximately 65 years old or older. The termination structures on both sides of the Portage Canal are significantly deteriorated and need to be replaced with equipment that meets current safety and construction standards. These two 3-phase underwater cables are important tie points for the cities of Houghton and Hancock as well as the surrounding areas that are served by the substations in the cities, specifically Elevation St in Hancock and Henry St and MTU in Houghton. These three substations serve more than 9,800 customers -- nearly 17% of all UPPCO customers -- including 1,300 commercial and industrial customers. These are the only distribution ties between the land mass south of the Portage Lake Lift Bridge and the land north of the bridge serving all of Keweenaw County and the northern third of Houghton County. To put this in perspective, UPPCO serves 3 counties in the Houghton District – Baraga, Houghton, and Keweenaw – serving 24,300 customers, and of those 14,000 are located on the “island” north of the Portage Lake Lift Bridge.

These crossings have been utilized over the years to support the load during emergencies and to accommodate planned maintenance events. The Henry St and MTU substations are fed from the ATC’s radial transmission line and the underwater tie lines have been used to maintain power flow to the customers served from both substations during planned and emergency transmission events. Additionally, these two 3-phase ties help support Elevation St load during transmission or substation outage events. Without these ties, thousands of UPPCO customers would lose redundancy that Houghton and Hancock have relied on over the last 65+ years and jeopardizes UPPCO’s ability to serve these customers during major substation or transmission outage events. This project will install two new 3-phase 1,500 ft underwater crossings to maintain the redundancy currently in place and increase the load carrying capacity of these tie points.

Q. Please describe SHARP project, M38 749 Mansfeldt Rd rebuild

A. This feeder is the 11th worst performing feeder based on outage data from 2020-2022. The existing 1-phase overhead facilities consist of old 1-phase copper conductor and aged poles serving 57 customers in the Mansfeldt Road who have been experienced multiple outages over this period. Converting 15,000 ft of overhead facilities to underground will reduce the vegetation impact and mitigate the maintenance needed on the system.

Q. Please describe SHARP project, UPPCO Cutout Replacement.

A. UPPCO's cutout replacement program began in 2023. Porcelain cutouts have experienced breakage over the past 20 years or so. Over the 5-year period of 2019 to 2023, cutout failures accounted for nearly 50% of customer outage coded as distribution equipment failures in UPPCO's Outage Management System ("OMS") resulting in 40% of the total SAIDI for equipment failures; therefore, a concerted effort to replace porcelain cutouts on a wholesale basis was initiated due to the long duration outages experienced by UPPCO customers when a porcelain cutout fails. This is a multi-year project that requires appropriate funding to complete.

Q. Please describe SHARP project, UPPCO Wide URD Replacement

A. This project was created and budgeted to address unforeseen cable replacement projects that arise during the course of the budget year. These projects typically develop due to cable failures. However, this funding could also be used if a customer-requested line relocation or line extension provides an opportunity for UPPCO to perform some additional work to take advantage of the customer project to improve reliability in the area. As mentioned earlier in my testimony, UPPCO anticipates replacement of underground cables due to failure and this budget item allows for these replacements during the course of the year, thereby providing flexibility to perform opportune cable replacements with a short turnaround time improving the reliability of the system serving those customers.

Q. Please describe SHARP project, Sys Hardening, OH to URD Conv, and Copper Replc.

A. This project was created and budgeted to address unforeseen reliability improvement projects that arise during the course of the budget year. This budget item allows for UPPCO Engineering to use discretion and judgement to design and complete small SHARP projects that may be completed in conjunction with other unplanned work. For example, customer requests, such as line relocations or line extensions, or shared facilities make-ready projects cannot be predicted, but when they develop, UPPCO can capitalize on a piggy-back project to improved reliability to all customers in the area. Other circumstances, such as storm restoration or overhead line inspection results, may warrant a more urgent system hardening project. This budget item allows for Engineering to perform a quick analysis of these situations and facilitate a project to make a direct and immediate impact in reliability for UPPCO's customers.

Q. Does this complete your direct testimony in this proceeding?

A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
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In the matter of the application of	)	
UPPER PENINSULA POWER COMPANY	)	
for authority to increase its rates for the generation	)	Case No. U-21555
and distribution of electricity and other relief.	)	
	)	

DIRECT TESTIMONY AND EXHIBITS OF

DANIEL J. GERVAE

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

March 21, 2024

QUALIFICATIONS

Q. Please state your name, business address and position.

A. My name is Daniel J. Gervae. My business address is 500 N. Washington St. Ishpeming, MI 49849. I am the Director of Substation & System Operations for Upper Peninsula Power Company ("UPPCO" or the "Company").

Q. For whom are you providing testimony?

A. I am providing testimony on behalf of UPPCO in support of its request for an increase in its retail electric rates.

Q. Please describe briefly your educational, professional, and utility background.

A. I have a Bachelor of Science degree in Electrical Engineering Technology from Northern Michigan University. I began my professional career in 1991 in the mining industry at Copper Range Company in White Pine, MI as a Supervisor of Mine Services where I oversaw installation of electric utilities and other infrastructure in the underground mine. I was later hired by MJ Electric out of Iron Mountain, MI as a Project Engineer, and was eventually promoted to Project Superintendent overseeing large electric utility construction projects from power plants to substations. I came to UPPCO in 2006 as a Substation Project Coordinator and in 2010 was Promoted to Supervisor of Substation Operations. In 2021 I became the Manager of Substation Engineering & Operations followed by a promotion to my present role as Director of Substation & System Operations.

PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to describe and provide support for UPPCO's projected capital projects relating to Substations.

EXHIBITS

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am co-sponsoring Exhibit A-7, Schedule B5.4 (JRR/DJG-1) Projected Distribution & Substation CAPEX by Business Driver, and sponsoring Exhibit A-19 (DJG-2) Substation CAPEX, which were prepared by me or under my direct supervision.

SYSTEM CONDITIONS

Q. Please provide an overview of UPPCO's Substation system.

A. UPPCO serves approximately 53,471 customers in Michigan's Upper Peninsula with a service territory of approximately 4,500 square miles in 10 of the 15 counties in the Upper Peninsula. UPPCO owns, operates, and Maintains 42 Substations and has a maintenance/operations agreement with ATC (American Transmission Co.) to provide services at 15 additional substations either jointly owned by UPPCO/ATC, or ATC only. We provide maintenance, switching, and construction services to ATC on an annual basis. UPPCO has 101 distribution feeders serving residential, commercial, and industrial customers across our service territory.

Q. Please describe Exhibit A-7, Schedule B5.4 (JRR/DJG-1).

A. In Exhibit A-7, Schedule B5.4 (JRR/DJG-1), I sponsor a summary of substation capital expenses during the historic year, bridge period, and test period.

Q. Please describe Exhibit A-19 (DJG-2).

A. Exhibit A-19 lists each substation-related CAPEX project planned for 2024 and 2025 with greater than $50,000 in projected costs. The exhibit lists the name of each project and the cost of each project that is anticipated during 2024 and 2025. The remainder of my direct testimony will describe each project, including the anticipated benefits to customers.

Q. Please describe, Ishpeming Substation Tools Project.

A. The Substation department installs high voltage equipment as well as complex relay protection and SCADA systems all of which require specialized tools to perform the required work. These tools include Doble transformer and breaker testing equipment, Omicron relay test sets, and many other very special, expensive tools. We have a service agreement with Doble Engineering for leased equipment and consulting services in support of those that cost $58,960 annually, circuit breaker test sets cost $32,970 each. We also routinely retire outdated test equipment and replace it with necessary, modern test equipment on a rotating basis to keep up with changing testing requirements. By testing our equipment during the commissioning phase of a capital project, we ensure the integrity of the new equipment and verify that it functions as designed. This process greatly improves reliability of our system and increases personnel and public safety.

Q. Please describe Atlantic RTU and R&C upgrade project.

A. The Atlantic substation has an old Opto 22 RTU. The software for this equipment is not supported and it will not run properly on a new 64bit PC. The controls (43, 101, GTB, 79CO, etc.) at the substation are virtual points on the HMI screen and are mapped to soft points in the Opto RTU. The obsolete panels will be removed to make room for one new panel. UPPCO will perform the design, construction, and checkout for all phases of this project. All SIS wire will be replaced with multi conductor control cable from the new panels to the MTC. Relay settings will be reviewed and coordinated with distribution engineering for new 387E and 351S relays. 351Ss will replace the 351Rs in the yard and will be located in the control house. Viper VCRs will be replaced with Cooper OCRs. RTU points list will be brought to our current standard. All local controls will be hardwired physical panel switches. The transfer trip scheme to MTU will be revised and coordinated with this project. This project is necessary because if we have a failure of our present outdated, unsupported equipment, we lose the ability to monitor and control our devices remotely from our System Operating Center, which would hamper restoration efforts and we would lose status visibility. Procurement and replacement of the required system would take months or longer based on material availability.

Q. Please describe Project Engineering Subsequent Years.

A. Substation engineering must adapt to changing material lead times and anticipate future project needs. We must have funds available to charge hours to in order to accommodate our future and unforeseen needs.

Q. Please describe Chatham Control Building Replace.

A. Chatham Substation has an old control building that is in poor condition. A controls and protection upgrade is planned and the new equipment located in an upgraded, weather and rodent proof building to protect this infrastructure and avoid potential reliability problems down the road.

Q. Please describe Nine 219A Voltage Regulator Upgrades Project.

A. The back-log for ordering new voltage regulators is 109 weeks, which forces the Company to anticipate future needs and place this equipment on order so that we can accommodate future age and condition upgrades as well as new load addition projects in a timely fashion.

Q. Please describe MTU Bank 1 Replace Aging Transformer Project.

A. The age and condition of the existing transformer (1967) as well as the size of the unit, force its replacement. The present transformer is a 8.4MVA 69/12.470KVA unit and we are replacing it with a 12/14/16MVA 69/12.47KV unit based on load interconnect requests from Michigan Tech as well as the need/ability to use this unit to back up other customer load in this same substation.

Q. Please describe MTU Bank 1 Transformer High Side Protection Project.

A. This project is directly related to the above MTU Bank 1 Transformer Replacement Project above, IEE recommends a high side breaker and relay protection for units above 10MVA for better system protection and reliability. This new equipment will be installed to protect the expensive and difficult to replace transformer. Lead time for procurement of a new transformer is approaching 2 years.

Q. Please describe Delta Bank 1 Transformer High Side Protection Project.

A. This project is directly related to the Delta Bank 1 Transformer Replacement Project from 2023, IEE recommends a high side breaker and relay protection for units above 10MVA for better system protection and reliability. This new equipment will be installed to protect the expensive and difficult to replace transformer. Lead time for procurement of a new transformer is approaching 2 years. UPPCO purchased the transformer in 2023 and are completing the project in 2024-25 with the addition of a new protection and controls package.

Q. Please describe Delta RTU and R&C (Relay & Controls) Upgrade Project.

A. The Delta substation has an SEL RTAC brand Remote Terminal Unit (RTU). The controls (43, 101, GTB, 79CO, etc.) at the substation are virtual points on the Human Machine Interface (HMI) screen and are mapped to soft points in the RTAC RTU. We have had trouble with the operating system as it relates to the HMI Function of this unit. The RTAC RTU will be reprogrammed using HMI view only Function and traditional 101, 43, 79CO, switches will be installed. Relay settings will be reviewed and coordinated with distribution engineering for new 387E and 351S relays. 351Ss will replace the 351Rs in the yard and will be located in the control house. Old OCRs will be replaced with New Cooper OCRs. RTU points list will be brought to our current standard. All local controls will be hardwired physical panel switches. UPPCO will perform the design, construction, and checkout for all phases of this project. In its present state, this RTU has limited function and the included protection upgrade is being completed due to age and condition of the microprocessor relays SEL 351R type that are reaching obsolescence. The local switching functions within the control panel are performed using soft points presently which we intent to change to a more traditional manual control for onsite switching and still retain remote function making the design more reliable.

Q. Please describe M38 138/12.47KV Transformer & High Side Protection Project.

A. M38 Substation distribution is fed from the 69KV bus by a 69/12.47KV 7.5MVA transformer that was manufactured in 1967, the age and condition of this unit, along with the fact that the Company can better serve its customers from the 138KV bus make this project a good one. In the present configuration, UPPCO will install a mobile transformer to serve customer load in order to perform equipment maintenance in many instances which otherwise requires service outages during the installation and removal of the mobile equipment. The addition of the new transformer on the BES (bulk electric system)138kv bus owned by ATC requires the Company to install upgraded relay protection and a new gas circuit breaker to protect the transformer and the associated bus. This project involves capital expenditures in both 2024 and 25 due to long lead times on required equipment.

Q. Please describe the 2025 M38 138/12.47KV Transformer progress Payments Project.

A. Referencing the previous stated project at M38, the Company is being required by its vendor(s) to provide payments as follows: 30% down, 30% at drawing approval, & 40%

on delivery. Because these units cost over $700,000 each and require long lead times, UPPCO has spread this cost across two budget years.

Q. Please describe the 2025 Munising 69/12.47KV Transformer progress Payments Project.

A. To plan for and complete a future transformer replacement project at Munising Substation due to age and condition of one of the transformers there (all transformers at this site were manufactured between (1959-1968), UPPCO must purchase the transformers by providing payments as follows: 30% down, 30% at drawing approval, & 40% on delivery. Because these units cost over $700,000 each, and require long lead times, UPPCO has spread this cost across two budget years.

Q. Please describe the 2025 Chatham 69/12.47KV Transformer progress Payments Project.

A. To plan for and complete a future transformer replacement project at Chatham Substation due to age and condition of one of the transformers there (manufactured 1967), UPPCO must provide payments as follows: 30% down, 30% at drawing approval, & 40% on delivery. Because these units cost over $700,000 each, and require long lead times, UPPCO spread this cost across two budget years.

Q. Please describe the 2025 Keweenaw Sub High Side Protection Project.

A. Because of the remoteness and distance from our service center, Keweenaw Sub can be more difficult to respond quickly to issues there. Adding a 69KV breaker on the high side of the transformer will give SCADA indication of that device, while at the same time providing better protection to the transformer. Transformers are expensive and involve long lead times for ordering replacements, so UPPCO is proactively prolonging the service lives of the existing transformers..

Q. Please describe the 2025 Ontonagon Bank 2 Replace Aging Transformer Project.

A. To plan for and complete a future transformer replacement project at Ontonagon Substation in 2026 due to age and condition of one of the transformers there (manufactured 1967), UPPCO must provide payments as follows: 30% down, 30% at drawing approval, & 40% on delivery. Because these units cost over $700,000 each, and require long lead times, UPPCO has spread this cost across two budget years. UPPCO intends to design and spec equipment in 2025 which will include at least the initial 30% down payment for the transformer plus design costs and the remainder of the capital expenses will be incurred in 2026 for this project.

Q. Please describe the 2025 Replace Viper, MTU, Seney, Bayview with OCR's Project.

A. As we have upgraded our system protection over the last few years it became clear that Oil Circuit Reclosers ("OCR's") were more reliable and accommodated our SEL 351S relay protection design better. These G&W vipers are the last-of-their-kind on our system and are 20 years old. This project will replace these units with the new, more reliable equipment.

Q. Please describe the 2025 Chatham Replace Aging Transformer (UHV-1733) Mfg 1967 New 5-7MVA Project.

A. To quote an earlier listed project "To plan for and complete a future transformer replacement project at Chatham Substation due to age and condition of one of the transformers there (manufactured 1967), UPPCO must provide payments as follows: 30%

down, 30% at drawing approval, & 40% on delivery. Because these units cost over $700,000 each, and require long lead times, UPPCO must spread this cost across two budget years." This project is phase 2 involving the construction phase after delivery of the unit. The final payment estimate is $287,000 and site work, foundations, wiring, and testing are all required for this installation.

Q. Please describe the 2025 328A Voltage Regulators Project.

A. Because the manufactures have quoted over 100wk lead time for these units, UPPCO must look ahead at future project needs and anticipate certain load conditions forcing replacement of existing units. This project allows the Company to place its order as early as possible and budget for delivery nearly two years later.

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
***

In the matter of the application of	)	
UPPER PENINSULA POWER COMPANY	)	
for authority to increase its rates for the generation	)	Case No. U-21555
and distribution of electricity and other relief.	)	
	)	

DIRECT TESTIMONY AND EXHIBITS OF

VIRGIL E. SCHLORKE

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

March 21, 2024

QUALIFICATIONS

Q. Please state your name, business address and position.

A. My name is Virgil E. Schlorke, and my business address is 800 Greenwood St. Ishpeming, MI 49849.

Q. For whom are you providing testimony?

A. I am providing testimony on behalf of UPPCO in support of its request for an increase in its retail electric rates.

Q. Please describe briefly your educational, professional, and utility background.

A. I graduated from Michigan Technological University with a Bachelors and Master of Science in Civil Engineering. I am also a licensed Professional Engineer in the states of Michigan and Wisconsin. I have over twenty-eight years of engineering and management experience, seventeen of which are in managing electric generation assets, and over eleven years in structural engineering and design, project construction management for industrial buildings and building restoration. I started in the utility industry in June of 2006 as a Regional Generation Supervisor at Wisconsin River Power Company. In July of 2010, I transferred to UPPCO as the Manager of Generation, and was promoted to my current position of Director of Generation and Environmental Services in February 2015.

PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to describe and provide support for UPPCO's projected capital projects relating to Generation.

EXHIBITS

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits, which were either prepared by me or under my direct supervision:

1. Exhibit A-7 Schedule B5.1 (VES-1) Projected Power Generation CAPEX Summary
2. Exhibit No A-20 (VES-2) UPPCO Generation CAPEX

GENERATION SYSTEM CONDITIONS

Q. Please provide an overview of UPPCO's Generation facilities.

A. UPPCO owns, operates, and maintains five hydroelectric generation facilities and three storage reservoirs producing on average 120,953 megawatts of clean renewable energy annually. The hydroelectric facilities are operated under Federal Energy Regulatory Commission (FERC) granted licenses. The license is a contract with the federal government, which requires the licensee to produce and deliver electricity while also ensuring public safety and meeting numerous other environmental and recreational requirements. The primary driver behind the Company's investment in its hydroelectric facilities is to ensure and maintain compliance with the FERC license while continuing to provide safe and reliable renewable energy to the benefit of its customers. Projects within the generation fleet are generally identified and prioritized by working with the regulators, resource agencies and consultants while considering material availability, equipment obsolescence and resource constraints.

Q. What types of capital projects does UPPCO plan for its hydroelectric generation fleet?

A. Projects within the UPPCO hydroelectric generation fleet generally fit into 3 different categories as follows.

1. Projects focusing on Facility Refurbishment/Improvements. These projects ensure license compliance by maintaining the integrity and extending the life of the facilities and building structures. These structures protect the generating equipment and ancillary components, while also directly and indirectly supporting the operation and maintenance of the equipment allowing the Company to maintain compliance with their FERC license.

2. Projects focusing on Power Generation & Delivery. These projects ensure license compliance by maintaining the integrity and extending the life of the generating and electric delivery equipment and systems. Safe and operational generating equipment and electric delivery systems are a requirement of the FERC license.

3. Projects focusing on Dam Safety. These projects ensure license compliance by maintaining the integrity and extending the life of the water conveyance and retaining structures. Structurally sound and safe water conveyance systems and retaining structures (such as penstocks, surge tanks, dams, embankments,

spillways, etc.) are required by the FERC license as a means to ensure public safety.

CAPITAL PROJECTS RELATING TO GENERATION

Q. Please describe Exhibit A-7 Schedule B5.1 (VES-1).

A. Exhibit A-7 Schedule B5.1 (VES-1) summarizes the Company's capital expenses for generation facilities during the historic period, the bridge period, and during the projected test year. Capital projects with expenses that are projected to exceed $100,000 in either the bridge period or the projected test year are presented in Exhibit A-20 (VES-2).

Q. Please describe Bond Falls Left Embankment Groin Filter, as shown at row 1 of Exhibit A-20 (VES-2).

A. This project is a multi-year project. Design & engineering were completed in 2022 with installation scheduled for 2024. Total project cost is estimated at $402,708. The project is categorized as Dam Safety because it addresses a potential seepage/piping erosion embankment failure. The left embankment groin at Bond falls has two drainpipes which were installed in the 1960's that have deteriorated and are unfiltered allowing for sand movement (seepage/piping erosion). Additionally, there is surface seepage in a riprapped collection ditch along the abutment contact that is also unfiltered (potential seepage/piping erosion). UPPCO and FERC had concerns with the unfiltered seepage and sand movement leading to an embankment failure, which is a dam safety issue and could result in license deviations/violations, public safety issues and significant environmental impacts. This project will install an aggregate filter system (address/stops seepage/piping erosion) to intersect the pipes and cover the riprap drain ditch collecting all the known seepage and transferring it to the existing monitoring weir. The project addresses dam safety issues, ensuring license compliance and public safety while avoiding environmental impacts. There are no feasible alternatives to address the public safety concerns, avoid environmental impacts and ensure continued license.

Q. Please describe Victoria Access Road Resurfacing & Drainage, as shown at row 2 of Exhibit A-20 (VES-2).

A. This project is planned for 2024 with a total project cost estimated at $260,670. The project is categorized as Facility Refurbishment/Improvements because it maintains/improves access to the facility. Over the years continued maintenance/grading and snow removal have thinned/removed the gravel ware surface and road crown resulting in increased susceptibility to rain runoff induced erosion. Runoff induced erosion could lead to access issues. Being unable to respond to developing conditions/issues in a timely fashion due to access restrictions may lead to extended outages and/or dam failure resulting in noncompliance with our FERC license. The access road surface will be replaced and shaped to direct runoff avoiding erosion and therefore ensuring continued safe access. There are no other alternatives to ensuring continued safe access.

Q. Please describe McClure Surge Tank Roof Replacement, as shown at row 3 of Exhibit A-20 (VES-2).

A. This project is planned for 2024 with a total project cost estimated at $208,536. The project is categorized as Facility Refurbishment/Improvements because it maintains a structure which is part of the facility needed to ensure continued safe operation. The McClure surge tank is a concrete and brick structure with a steel roof located approximately halfway between the powerhouse and intake structure. It is meant to balance pressure spikes in the penstock resulting from sudden flow adjustments. If the tank were to fail, it would result in equipment damage, extended outages and potential public safety issues. During a storm, high wind peeled back a portion of the steel roof exposing the top of the tank walls and supporting roof structure. Portions of the wall (brick) fell into the penstock because of this event, which led to some initial equipment damage in the powerhouse. An initial assessment of the roof and roof support structure has been completed, indicating that roof replacement is necessary. While the Company was developing a plan to complete roof replacement, an unknown person threw additional debris through the opening in the roof (a rock) which caused additional equipment damage. Failure of the McClure surge tank and/or the continued potential for vandalism could lead to a catastrophic failure of the equipment and result in license deviations/violations, environmental impacts, and public safety issues. This project will replace the roof - not only ensuring surge tank integrity but also keeping unwanted equipment damaging debris out of the system. There are no other alternatives to ensure surge tank integrity and protecting equipment from debris that would enter through the surge tank roof area.

Q. Please describe Victoria – Controls upgrade, as shown at row 4 of Exhibit A-20 (VES-2).

A. This project is a multi-year project. Project scoping and bidding was completed in 2021, Equipment Design & Plant Engineering were completed in 2022-2023 with installation scheduled for 2024. Total project cost is estimated at $1,668,721. The project is categorized as Power Generation & Delivery because it addresses a potential energy generation equipment control failure. The existing progressive logic control (PLC) control system and generator unit governors are being replaced with modern PLC controls and a low volume high pressure hydraulic governor system controlled by the new PLC system. The current PLC control system uses an obsolete platform that is difficult to maintain due to component obsolescence. The governors are original 1930s mechanical systems that although functional use a large quantity of oil and pose significant environmental risk related to oil releases. Maintenance and repair of these governors is challenging due to age, parts obsolescence, and lack of maintenance personnel with technical understanding of these systems. A failed controls system would result in license deviations/violations. The project addresses equipment obsolescence and reliability ensuring license compliance. There were no feasible alternatives to address obsolete equipment and ensure continued license compliance.

Q. Please describe Prickett Unit 2 Overhaul/Rewind, as shown at row 5 of Exhibit A-20 (VES-2).

A. This project is planned for 2024 with a total project cost estimated at $990,546. The project is categorized as Power Generation & Delivery because the project addressed generating equipment potential failure issues. Generating Unit #2 at the Prickett powerhouse was installed in 1931 and has had partial rebuilds and repairs done over the last 90 years. The Unit is due for a major overhaul, including complete disassembly to allow for a full inspection of all major components. Recent inspections have identified issues related to scroll case corrosion/cavitation, wicket gate corrosion/cavitation/seals, turbine runner cavitation and cleanliness of the generator. Electrical testing of the unit's generator and exciter components has indicated a partial short in the rotor. The electrical components are not functioning at optimal levels, likely due to the extensive amounts of oil and debris baked onto the windings and coils from multiple years of small oil weeps. With no history on the generator's past, it is assumed that all rotor poles and stator coils are original to the 1931 installation. Recent failure trends have provided additional scrutiny from the risk insurance companies for generators assembled before 1950 due to the use of asbestos and asphalt winding insulations. In the event of a phase-to-phase fault inside the generator, the asphalt windings could combust resulting in a unit fire. Due to the age and extensive oil-soaked condition of the unit, a complete rewind of the generator rotor and stator has been a high priority recommendation from the risk insurance group (to extensively clean and remove asphalt and asbestos insulators). Failure of the generating unit due to anyone of the above-mentioned items would be catastrophic and result in license deviations/violations, potential employee safety issues and environmental impacts. The project addresses all these issues by disassembling the unit and sending the generator stator & rotor out for rewinding and sealing. The runner was also sent to a fabrication shop where all cavitation damage will be repaired, and an epoxy type coating applied to the runner. There are no feasible alternatives to address the potential equipment failure issues and ensure continued license compliance.

Q. Please describe Hoist Unit 3 – Penstock Valve Replacement, as shown at row 6 of Exhibit A-20 (VES-2).

A. This project is a multi-year project. Design, engineering, and procurement were completed in 2022-2023 with installation scheduled for 2025. Total project cost is estimated at $359,052. The project is categorized as Facility Refurbishment/Improvements because it replaces the existing poorly functioning and unsafe valve with a new value that allows single unit isolation and provides for safe entry into the unit for inspections and maintenance. The current Unit 3 Isolation valve is original to the powerhouse expansion/unit installation in the 1940's. The valve leaks severely due to worn and antiquated valve sealing surfaces and design. Due to the inability for this valve to provide the needed unit isolation from the penstock, routine maintenance work is hard to schedule and at times postponed because it requires the entire powerhouse to be taken offline. The inability to complete routine maintenance and conduct inspections could lead to unit failure which would result in license compliance issues and potential deviations/violations along with environmental impacts. The project will addressed these issues, ensuring license compliance while avoiding environmental impacts.

Q. Please describe McClure Unit 1 Overhaul/Rewind, as shown at row 7 of Exhibit A-20 (VES-2).

A. This project is planned for 2025 with a total project cost estimated at $832,000. The project is categorized as Power Generation & Delivery because the project addresses generating equipment operation and potential failure issues. McClure Unit #1 has limited operation due to significant cavitation and vibration issues. It is believed the vibration issue is caused by the cavitation damaged runner. There are limited records on vibration readings and internal inspections, but current inspections and readings indicated there may also be an alignment issue, likely due to the increased vibration caused by the cavitation. Additionally, routine electrical testing of the unit's generator and exciter components indicates electrical components are not functioning at optimal levels. Polarization index (PI) tests are low, likely due to the extensive amounts of oil and debris baked onto the windings and coils from multiple years of small oil weeps. With no history on the generator's past, it is assumed that all rotor poles and stator coils are original to the installation. Recent failure trends have provided additional scrutiny from the risk insurance companies for generators assembled before 1950 due to the use of asbestos and asphalt winding insulations. In the event of a phase-to-phase fault inside the generator, the asphalt windings could combust causing a unit fire. Due to the age and extensive oil-soaked condition of the unit, a complete rewind of the generator rotor and stator has been a high priority recommendation from the risk insurance group (to extensively clean and remove asphalt and asbestos insulators). Failure of the generating unit due to any of the above-mentioned items would be catastrophic and result in license deviations/violations, potential employee safety issues and environmental impacts. The project addresses all these issues by disassembling the unit and sending the generator stator & rotor out for rewinding and sealing. The runner will also be sent to a fabrication shop where all cavitation damage can be repaired, and an epoxy type coating applied to the runner. There were no feasible alternatives to address the potential equipment failure issues, generator derates and ensure continued license compliance.

Q. Please describe Annual New Equipment / Generation Tools., as shown at row 8 of Exhibit A-20 (VES-2).

A. This is an ongoing project made up of multiple smaller and/or unidentified projects from year to year and is budgeted at $208,536 in 2024 and $208,000 in 2025. The projects will typically fall into the categories of Facility Refurbishment/Improvements or Power Generation & Delivery. The individual projects typically range between $5,000 and $50,000. Some recent and planned projects under this blanket project are; Prickett Fire Protection Upgrade (estimated $19,000), Hoist Buoys Replacement (estimated $65,511), McClure Hand Tools (estimated $9,061), Hoist Hand Tools (estimated $2,593), McClure Buoys Replacement (estimated $14,000), Hoist Fire Protection Upgrade (estimated $19,650), Prickett Embankment Access Stairs (estimated $12,000), Victoria Powerhouse Backup Power Transfer Switch (estimated $15,000), Pricket Powerhouse Alternative Heat (estimated $15,000), McClure Fire Protection Upgrade (estimated $18,650) etc. These projects are required to ensure license compliance, public & employee safety, along with facility integrity and dam safety. Without proper fire protection systems, safety buoys, tools, backup heat etc. individual components could fail potentially leading to a significant failure resulting in license deviations, environmental impacts, and public safety issues. Having a blanket project from year to year that provides resources for these smaller and at times unidentified projects ensures a timely response and therefore license compliance and continued reliable renewable energy.

Q. Please describe Bond Falls Inundation Mapping, as shown at row 9 of Exhibit A-20 (VES-2).

A. This project is scheduled for 2025 with a total estimated cost of $101,982$. The project is categorized as Dam Safety because it addresses a deficiency in the dam safety program Emergency Action Plan (EAP) requirements set out by the Federal Energy Regulatory Commission (FERC). FERC requires hydro project licensees to develop and maintain an EAP that covers the owner's response to a dam failure and provides information on inundation during a failure. The Bond Falls inundation mapping, which is a key component to the EAP, was developed in 2010 using modeling methods which no longer meet industry standards combined with overly course contours leading to potentially inaccurate inundation zones. Also, recent Functional exercises of UPPCO’s EAPs have resulted in recommendations from FERC and other attendees to improve the inundation mapping. Additionally, the new FERC Comprehensive Assessment (CA) process requires additional inundation information (depth & velocity of inundation waters) to complete a risk analysis which incorporates the consequences of a dam failure. The issues associated with the inundation mapping combined with the need for additional inundation information to support the CA process result in an unacceptable deficiency in our emergency planning and license compliance. Not addressing these issues could potentially lead to license violations and public safety concerns. This project will use current industry standard modeling, which provides the required additional information and results in more accurate maps therefore addressing the issues, ensuring license compliance and public safety while bringing UPPCO's Bond Falls inundation mapping up to current industry standards.

Q. Please describe Hoist, McClure, Silver Lake Dam Concrete Refurbishment, as shown at row 10 of Exhibit A-20 (VES-2).

A. This project is a multiyear project with engineering scheduled for 2024. Project engineering costs are estimated at $103,955. The project is categorized as Dam Safety because it addresses FERC commitments for concrete refurbishment resulting from the FERC required Part 12 Consultant Dam Safety Inspections of the Silver Lake, Hoist, and McClure Dams in 2021. These concrete refurbishment items have been bundled into a single engineering/design effort to maximize efficiencies and minimize duplication of work associated with multiple sites and the resulting overall number of regulatory filings. Key items included as part of the concrete refurbishment for each facility are as follows.

Silver Lake: Addressing current areas of eroded rock and preventing further undermining of the spillway due to rock erosion during spill events.

Hoist: Refurbishment of the upstream face of the concrete dam & spillway mostly along the water line area which has experienced freeze thaw deterioration. Refurbishment of the crest and downstream face of the concrete dam (including the thrust block) in areas that have experienced freeze thaw deterioration. Filling of the glacial pothole which is undercutting the toe of the concrete dam. Refurbishment of the powerhouse access walkway.

McClure: Refurbishment of the concrete dam's left intake buttress and non-overflow structure (including crack injection & grouting in the upstream intake stoplog slots).

Not addressing these commitments would result in license compliance issues and potential dam safety problems leading to public safety concerns. The project will address all the FERC required Part 12 commitments ensuring license compliance and public safety.

Q. Please describe Bond Falls Canal Rip Rap, as shown at row 11 of Exhibit A-20 (VES-2).

A. This project is scheduled for 2024 with an estimated cost of $104,268. This project is categorized as Dam Safety because it ensures the integrity of the canal system water retaining embankment. The Bond Falls canal routes water from the Bond Falls reservoir to Roselawn Creek (which eventually flows into Victoria development). The canal system was constructed by bench cutting into a hill side and forming an earthen embankment on the downhill side to contain the flowing water between the embankment and the hill side. Because of steep slopes and sandy material, the earthen embankment is susceptible to erosion by the flowing water. Continued erosion could potentially lead to embankment failure and an uncontrolled release of water resulting in license deviations/violations, environmental impacts, and public safety issues. This project will place geotextile material and riprap stones in the aeras of erosion to stabilize and armor the embankment preventing further erosion and ensuring license compliance and public safety while avoiding environmental impacts.

Q. Please describe Prickett Intake Refurbishment, as shown at row 12 of Exhibit A-20 (VES-2).

A. This project is a multi-year project. Design development, engineering and planning are scheduled for 2024. Design development & engineering are estimated at $104,268. This project is categorized as Dam Safety because it addresses a potential intake structure stability issue. Sediment movement from under the Intake structure has been identified along with instrumentation indicating increased uplift pressure under the intake structure, resulting in stability safety factors lower than FERC required guidelines. Increased uplift pressure during a flood event could result in a failure of the intake structure resulting in a complete release of the reservoir. This would be considered a dam safety event and result in significant environmental impacts, public safety and employee safety issues and license deviations/violations. Dive inspections identified a crack in the intake floor/foundation which when plugged (temporally) provided significant reductions in uplift pressures. Incorporating this information along with the understanding sediment has also been moving suggests the remediation/refurbishment will most likely consist of foundation grouting and crack injection, which will stabilize the foundation (fill any voids) along with providing a seepage cutoff resulting in lower uplift pressures. This would address the dam safety issues, ensure license compliance, public safety and employee safety while avoiding environmental impacts.

Q. Please describe Victoria Gate Hoist Replacement, as shown at row 13 of Exhibit A-20 (VES-2).

A. This project is a multi-year project. Design and engineering are ongoing with procurement scheduled for 2025 ($624,000). The project is categorized as Dam Safety because it addresses the potential inability to operate a traveling gate hoist which controls 75% of the gated spillway capacity. The current traveling gate hoist serves 3 gates and is original 1930's equipment. Maintenance of the hoist has become increasingly challenging due to equipment and component obsolescence. Additionally, the current hoist is time consuming to operate, labor intensive, poses significant employee safety risks and has no remote operation capability. A significant amount of the site’s spillway capacity (75%) is dependent on this local operated hoist where access to the site is difficult during major storms and requires use of bridges susceptible to flooding during PMF level storm events. The inability to operate the traveling hoist would potentially lead to overtopping and failure of the facility. This would result in significant license deviations/violations, public safety issues and environmental impacts. This project replaces the single traveling gate hoist with 3 new remote operated hoists. This address equipment obsolescence and provides for safer and more timely gate operation while ensuring license compliance, public safety, and protecting the environment.

Q. Please describe Hoist Penstock Interior Lining Replacement, as shown at row 14 of Exhibit A-20 (VES-2).

A. This project is planned for 2025 with a total project cost estimated at $572,000. The project is categorized as Dam Safety because it addresses the failing interior lining of the Hoist Penstock. This lining is meant to protect the interior of the penstock from corrosion and was identified as peeling away and missing in some places during an internal inspection in 2021. Excessive corrosion would lead to thinning and potential failure of the penstock. Penstock failure is considered a dam safety issue and would cause significant environmental impacts, potential public and employee safety issues and result in license deviations/violations. The project replaces the interior lining protecting the penstock from internal corrosion and therefore addresses the dam safety issue, ensuring license compliance and public safety while avoiding environmental impacts.

Q. Please describe McClure Substation Refurbishment, as shown at row 15 of Exhibit A-20 (VES-2).

A. This project is a two-phase project. The transformers procurement was phase 1 completed as a separate project in 2023 ($970,000). Phase 2 is substation design and installation and is scheduled for 2025. Total phase 2 project cost is estimated at $1,842,204. The project is categorized as Power Generation & Delivery because it addresses a potential energy delivery equipment failure issue. The McClure Substation consists of two GSU transformers, associated breakers, switches, steel support structures and metering components. The existing GSU transformers are 75 years old and at the end of their life. The potential/risk of catastrophic failure is a concern. Additionally, asset insurance providers have identified the current substation layout does not meet minimum NFPA recommendations for spacing between transformers and buildings. The failure of the transformers would result in significant equipment and building damage which, based on the latest insurance provider recommendation, may not be fully covered. This failure would also result in environmental impacts, potential employee & public safety issues, and an extended outage leading to license deviations/violations. This project will replace the 75-year-old GSU transformers, adjust the equipment layout to meet NFPA standards, and incorporate containment therefore mitigating environmental impacts, ensuring license compliance along with employee & public safety.

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
***

In the matter of the application of	)	
UPPER PENINSULA POWER COMPANY	)	
for authority to increase its rates for the generation	)	Case No. U-21555
and distribution of electricity and other relief.	)	
	)	

DIRECT TESTIMONY AND EXHIBITS OF

JASON J. BRYNICK

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

March 21, 2024

Q. Please state your name, business address and position.

A. My name is Jason J. Brynick. My business address is 500 N. Washington St, Ishpeming, MI 49849. My position is Senior Project Manager for Upper Peninsula Power Company ("UPPCO" or the "Company").

Q. For whom are you providing testimony?

A. I am providing testimony on behalf of UPPCO in support of its request for an increase in its retail electric rates.

Q. Please describe briefly your educational, professional, and utility background.

A. I have two Bachelor of Science Degrees from Michigan Technological University, in Civil Engineering and Business Administration with a Minor in Entrepreneurship, that I attained in 2004. From 2004-2013 I worked through various roles within the Heavy Highway Civil Industry for Granite Construction, Walsh Construction, and Penhall Company. These roles included Project Engineer, Project Superintendent, Estimator, Project Manager and Operations Manager. From 2013-2018 I worked within the Utility Industry for M.J. Electric and Google Fiber in the capacity of Project Manager and Program Manager respectively. From 2018-present I've been Project Manager and Senior Project Manager for UPPCO helping implement capital projects across all areas of the business.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the Company's proposed capital expenditures ("CAPEX") relating to facility, fleet, and Advanced Metering Infrastructure ("AMI").

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits, which were either prepared by me or under my direction:

1. Exhibit A-7, Schedule B5.5 (JJB-1) – AMI CAPEX
2. Exhibit A-7, Schedule B5.6 (JJB-2) – Total Corporate | General Plan CAPEX
3. Exhibit A-18 (JJB-3) – UPPCO Facility CAPEX
4. Exhibit A-54 (JJB-4) – 2023 UPEA Houghton Facility Assessment
5. Exhibit A-55 (JJB-5) – Existing Houghton Site Layout – Phase 1 ESA
6. Exhibit A-56 (JJB-6) – Final Bid Results
7. Exhibit A-57 (JJB-7) – Houghton Service Center Appraisal
8. [CONFIDENTIAL] Exhibit A-58 (JJB-8) Phase 1 ESA
9. Exhibit A-59 (JJB-9) – Quincy Hill Project Cost Analysis
10. Exhibit A-60 (JJB-10) – Quincy Hill Project Net Cost Analysis
11. Exhibit A-61 (JJB-11) – Regional Map of Houghton Area Operations
12. Exhibit A-62 (JJB-12) – UPEA Avoided Costs

Q. Please describe Exhibit A-7, Schedule B5.5 (JJB-1).

A. Schedule B5.5 of Exhibit A-7 details the AMI related CAPEX that the Company completed during the historic test period, and is expected to undertake during the projected bridge period and the projected test period.

Q. Please describe Exhibit A-7, Schedule B5.6 (JJB-2).

A. Schedule B5.6 of Exhibit A-7 details CAPEX related to Information Technology ("IT"), fleet, facility, and special projects that the Company completed during the historic test period, and is expected to undertake during the projected bridge period and the projected test period. Company witness Kates supports the proposed IT-related CAPEX in his direct testimony.

Q. Please describe Exhibit A-18 (JJB-3).

A. Exhibit A-18 details the facility related capital projects that the Company intends to undertake during 2024 and 2025. Of note, the remainder of my testimony will focus on the Hancock/New Houghton Service Center project detailed at Line 1 of Exhibit A-18.

Q. Please describe the existing Houghton Service Center.

A. A facility description is provided below.

1. Location. The Houghton Service Center is at 18494 Canal Road in Section 34 of Township 55 North, Range 34 West, in Houghton County, Michigan. This small 6.896-acre parcel is on the western end of Houghton and is along the southern shores of the Portage Waterway (canal). This facility is the primary operations depot for the western end of UPPCO's service territory, servicing the counties of Houghton and Keweenaw counties, and parts of Ontonagon and Baraga counties. Please see Exhibit A-61 (JJB-11), Regional Map of Houghton Area Operations.
2. Known History. The property on which the current Houghton Service Center currently resides was reportedly first developed as a brewery in the late 1800s. Bosch Brewing Co. operated a brewery at the property from 1899 to 1972 and then sold the property to UPPCO in 1975. Additional portions of the property were purchased in 1979 from the Copper Range Company who operated a railroad line that crossed the southern portion of the property and the adjoining

property to the south. Details of the historic use and ownership of the property, including activities associated with the manufacturing of alcoholic beverages and mining/railroad operations, prior to 1975/1979 are not known at this time as no reasonably ascertainable records are available for review. Please see Exhibit A-55 (JJB-5) Existing Houghton Site Layout – Phase I ESA at page 1.

3. Operational Considerations.

a. Age and Condition. Please see Exhibit A-55 (JJB-5), Existing Houghton Site Layout – Phase I ESA at page 2 for building names and locations within property boundary. The service center is comprised of a central office building, labeled as the "Operations Building" which is estimated to be 70 years old, two partially utilized concrete buildings estimated to be each 100 years old, labeled as the "Wire Storage Building" and the "Storage/Workshop" (i.e., Former Hopps Building), and a garage building labeled as the "Garage/Shop" which is estimated to be close to 40 years old. It should be noted that the Former Hopps Building is a three-story concrete building that provides significant structural support to County Road P-554, thereby limiting structural modifications, and the same can be said for the Wire Storage Building. While not labeled on the map, there is an additional outside storage area for underground wire and cable located directly across from the Wire Storage Building because the reels are too big for the building.

b. Employees and Physical Assets. Approximately 35 employees report directly out of the Houghton Service Center. Also, over 42 fleet assets reside at this location, along with normal inventory levels valued at over $2.0 million. The parcel is currently valued at $1.160 million and represents prime waterfront property once utility operations are relocated. Please see Exhibit A-57 (JJB-7), Houghton Service Center Appraisal.

c. Customer Load / Reliability. The Houghton Service Center mainly services about 40 MW. Almost half of this load is located on the northern side of the Portage Waterway and requires any UPPCO service vehicles (or any vehicle for that matter) to cross via the Portage Lake Lift Bridge, also known as the Houghton-Hancock Bridge. This bridge is a vertical-lift bridge constructed in 1959 and serves as the only vehicular traverse point across the Portage Waterway.

Q. Has UPPCO performed an environmental assessment at the Houghton Service Center property? If so, please explain.

A. Upon acquisition of UPPCO by Balfour Beatty Infrastructure Partners in 2014, a Phase I Environmental Site Assessment (ESA) was completed. A copy of this Phase I ESA is evidenced in [CONFIDENTIAL] Exhibit A-58 (JJB-8), Phase I ESA. Results indicated the presence of recognized environmental conditions ("RECs") that fall within what would be considered normal business practices at an electric utility service center facility, as well as a REC associated with historic mining activity in the vicinity of the Property. In summary, while the Phase I ESA concludes that RECs exist within what would be considered normal business practices, the findings clearly impede UPPCO's practical ability to modify the existing site to provide continuous safety and operational improvements.

Q. Since the last Phase I ESA, has UPPCO had a comprehensive facilities review performed at the location. If so, please explain.

A. Yes. In February 2023, U.P. Engineers and Architects ("UPEA") assisted UPPCO in investigating several problem areas at the Houghton Service Center, and the associated costs to remedy them. At UPPCO's request, UPEA performed an assessment and identified several updates/upgrades that are required to maintain a working and productive facility for the next 10 years. Categorically, general civil site work and architectural updates were evaluated independently. While environmental factors have been considered, dollar values have not been assigned to those aspects. Please reference Exhibit A-54 (JJB-4), 2023 UPEA Houghton Facility Assessment for a copy of UPEA's report and findings.

Q. Please provide a list of the key facility updates/upgrades that UPEA identified as necessary for UPPCO to have a working and productive facility over the next 10 years?

A. As further categorized below, UPEA has identified architectural and civil update/upgrades totaling $4.292 million in nominal (current) terms. Please reference Exhibit A-62 (JJB-12), UPEA Avoided Costs.

1. Architectural maintenance projects
    a. Administration Building Roof Replacement: $247,650 (Year 4)
    b. Storage Building Roof Replacement: $50,800 (Year 5)
    c. All Buildings LED Lighting Upgrade: $317,500 (Year 7)
    d. Administration Building Flooring Replacement: $50,800 (Year 8)

e. Administration Building Ceiling Tile Replacement: $54,661 (Year 9)
f. Administration Building Window Replacement: $84,582 (Year 6)
g. Transformer Storage Replacement: $1,324,737 (Year 3)
h. All Buildings Painting and Lead Abetment: $188,976 (Year 10)
i. Asbestos Abetment (All Projects): $70,917 (Year 6)

2. Civil maintenance projects
   a. Parking Lot Repair: $319,659 (Year 1)
   b. Connect to City Water and Sewer: $687,673 (Year 1)
   c. Abandon Well & Septic: $27,686 (Year 2)
   d. Shoreline Protection: $760,705 (Year 2)
   e. Administration Building Roof Drain Replacement: $55,880 (Year 4)
   f. Garage Floor Drain and Wash Bay Addition: $21,742 (Year 4)

Q. Please provide a list of the environmental considerations that UPEA identified as necessary for UPPCO to have a working and productive facility over the next 10 years?

A. The environmental considerations are listed below. Please reference Exhibit A-54 (JJB-4), 2023 UPEA Houghton Facility Assessment on page 2.

1. Chemical containment – With the presence of hazardous chemicals in proximity to a Great Lake, additional measures should be taken to avoid interactions if spills were to take place.
2. Offsite Storage of Hazardous Materials (Temporary and Permanent) – Even temporary storage of hazardous materials on site initiates a high risk for accidental soil, surface water, and groundwater contamination. Remedial needs for a spill of even small amounts

of certain chemicals (PCB's) could be extensive and long lasting. Proximity to a large water body and extremely shallow water table exasperate these possibilities.

Q. Why is UPPCO relocating its service center?

A. UPPCO's mission statement is to *keep the lights on* by investing responsibly in safety, reliability, and people. The justification for the new service center in Hancock lives at the intersection of safety, reliability, and people.

UPPCO is relocating the facility for the following reasons.

1. <u>Technical Engineering Conclusions</u>. The Phase I ESA report completed by Power Engineers, and the 2023 UPEA Houghton Facility Assessment provide overwhelming support that the current Houghton Service Center is nearing the end of its useful life.
2. <u>Environmental Analysis</u>. The environmental considerations provide significant qualitative value by highlighting potential hazards related to ongoing utility operations that remain proximate to a primary channel that flows directly into Lake Superior. While portions of the property appear to have been operated as a brewery from the late 1800's through 1972, a railroad right-of-way, the unknown historical use and ownership of the property create significant gaps in data/information and therefore present unknown risks when evaluating existing site expansion and/or any civil work that could potentially disturb the existing structure, geology and soils.
3. <u>Necessary Facility Updates/Upgrades and Costs</u>. UPEA identified $4.292 million in architectural and civil facility maintenance and remediation projects that would

be required over the next 10 years alone to ensure working and productive facilities.

When UPPCO makes capital and/or maintenance decisions, the health and safety of our employees, contractors and communities comes first. Simply put, the Houghton Service Center is nearing the end of its useful and productive life. This is an old and tired site that is far too small to support continued safe and efficient electric utility operations and logistics in the 21st century. For all the reasons outlined above, the Company firmly believes that a new location for the Houghton Service Center is the best course of action.

Q. Where is UPPCO planning to relocate the existing Houghton operations? Please explain.

A. The new location for Houghton operations will be developed on a greenfield site located in Hancock above the old Quincy Mine area. For purposes in this case filing, UPPCO will refer to this facility as the Quincy Hill Service Center. This new site will be a 15-acre site providing (1) ample size/acreage, (2) Class A road access with no road restrictions, and (3) straightforward access to city water and sewer, and other utilities.

Q. Please describe procurement, development, and construction activities to date for the new operations facility.

A. In planning for the eventual relocation of Houghton operations to a new location, the Company acquired the property site in Q1-2022 for price of $335,000. Early development work such as surveys and site investigations were completed through the better part of 2022 and into early 2023. In Q1-2023, the Company contracted with UPEA to help us construct an RFP bid package, including preliminary design, whereby a competitive procurement process would be administered resulting in the identification of a qualified, winning bidder.

- The RFP bid package was sent to 13 parties in November 2023.
- The final bidder list identified 3 final bidders from which the winning bidder was selected. The bid results are evidenced in A-56 (JJB-6), Final Bid Results.

In Q1-2024, UPPCO moved forward with site clearing and grubbing which would prepare the ground for construction beginning in 2024. This is currently where the Company is at from a development and construction perspective.

Q. Please provide the estimated "baseline" capital costs for the service center located at Quincy Hill.

A. The planned "baseline" cost for the Quincy Hill service center is $11.602 million[1]. Please reference Exhibit A-59 (JJB-9), Quincy Hill Project Cost Analysis. As defined by UPPCO, the "baseline" cost represents fully designed and engineered facility utilizing natural gas as its primary heat source.

Q. Is UPPCO done designing the heating and cooling attributes of this project? Please explain.

A. No. Currently, UPEA is in the process of providing an alternative mechanical/HVAC design that will maximize, within reason, efficient sources of electric heating and cooling. The results of UPEA's design alternative will be incorporated into the

[1] Reference Exhibit A-59, Quincy Hill Project Cost Analysis

Company's analysis when complete. This may or may not cause an incremental modification to the original $11.602 million project estimate.

Q. Please explain how is UPPCO planning account for changes due to the maximization of reasonable and efficient electric sources of heating and colling?

A. The Company is seeking approval to record in FERC Account 183 any changes in costs due to efforts to maximize, within reason, efficient sources of electric heating and cooling. Any incremental costs related to heating and cooling expenditures will be subject to review in the Company's next general rate case unless total project costs are less than $12.763 million[2], which represents a 10% overage threshold on project expenditures.

Q. Why is the Company seeking this FERC Account 183 treatment?

A. Timing. The Company believes that this heating/cooling alternative design and requested accounting treatment will (1) add value to the project decision-making process, (2) align with Michigan's clean-energy and electrification efforts, and (3) allow for the Company to pursue these efficiency efforts during the rate case proceeding while not slowing down the construction of the project.

Q. Please identify the project benefits that would lower the total capital cost of the new service center located at Quincy Hill.

A. Please reference Exhibit A-60 (JJB-10), Qunicy Hill Project Net Cost. With the existing Houghton Service Center having a market appraisal of $1.160 million[3] and with UPEA

[2] $12.763 million represents a value that is 110% of $11.602 million "baseline" capital cost of the facility.
[3] Reference Exhibit A-57, Houghton Service Center Appraisal

estimated avoided costs of $4.292 million[4] serving to offset the original $11.602 million cost, the net cost of the project is anticipated to be approximately $5.452 million.

Q. Please identify additional benefits of the new service center located at Quincy Hill.

A. Additional benefits are listed below.

1. <u>Safety Risk Mitigation</u>. By relocating to a new facility, UPPCO mitigates potential exposure risks to asbestos/lead paint, improves traffic patterns when entering and exiting key roadways leading to the existing facility.
2. <u>Environmental Risk Mitigation</u>. By relocating to a new facility away from the shoreline of the Portage Waterway, UPPCO mitigates the existing risk of a catastrophic environmental event simply due to the existing proximity of existing operations.
3. <u>Improved Reliability/Accessibility</u>. In the Houghton area, UPPCO serves approximately 24,179 customers. The majority of UPPCO's customers, approximately 13,964 or 58%, are located north of the Portage Canal with the remaining estimated 10,215 or 42% of customers located south of the bridge. By strategically relocating service center operations to the north side of the Portage Lake Lift Bridge, UPPCO is situating key operational support on the side of the bridge that has the largest load center. In the event the 60-year-old hydraulic bridge would pause and/or cease operations, UPPCO would be postured to service this load center north of the bridge. Any load south of the bridge, UPPCO could be serviced with our other service centers – most specifically, Ontonagon.

[4] Reference Exhibit A-62, UPEA Avoided Costs

4. <u>More Efficient and Safe Operations on Property</u>. General material handling and onsite vehicle navigation will be greatly improved at the new site thereby providing a safer, more operationally efficient worksite.

Q. Has the Company included any O&M savings with this project through the projected test year, December 31, 2025? Please explain.

A. No. Any incremental costs or savings attributable to this project are expected to be materially manifest after December 31, 2025.

Q. As represented in the Company's filing, is the project planned to be complete by the end of the projected test year, December 31, 2025?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
***

In the matter of the application of	)	
UPPER PENINSULA POWER COMPANY	)	
for authority to increase its rates for the generation	)	Case No. U-21555
and distribution of electricity and other relief.	)	
	)	

DIRECT TESTIMONY AND EXHIBITS OF

KAY L. RYAN

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

March 21, 2024

QUALIFICATIONS

Q. Please state your name, business address and position.

A. My name is Kay L. Ryan. My business address is 1002 Harbor Hills Drive, Marquette MI 49855. I am the Vice President of Human Resources for Upper Peninsula Power Company ("UPPCO" or "the Company").

Q. For whom are you providing testimony?

A. I am providing testimony on behalf of UPPCO in support of its request for an increase in its retail electric rates.

Q. Please describe briefly your educational, professional, and utility background.

A. I graduated from Ferris State University in 2000 with a Bachelor of Science in Human Resource Management and from Central Michigan University in 2012 with a Master of Science in Administration. My professional experience in Human Resources ("HR") covers over 20 years where I have been responsible for all aspects of human resources including, but not limited to, compensation and benefit design and administration, retirement plan administration, talent management, and labor relations. In June 2000 I entered into employment with Leprino Foods as a Safety Coordinator and in 2001 was promoted to the Plan Human Resources Manager. In December 2012 I left Leprino Foods and entered into employment with Potlach as a Plan Human Resources Manager and was promoted to the Regional Human Resources Manager in 2013. In 2014, I left Potlatch and joined UPPCO as the Director of Human Resources and assumed my current role as Vice President of Human Resources in 2019.

Q. Have you previously testified in any regulatory proceedings before the Michigan Public Service Commission ("MPSC" or "the Commission")?

A. Yes, in Case No. U-21286, UPPCO's 2022 general rate case proceeding.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present UPPCO's compensation structure and benefit plans for the 2023 historical period and 2025 projected test year. In summary, my testimony will provide a reasonable and valid projection of compensation and benefits expense incurred by the Company. I will discuss UPPCO's market-based approach to our overall compensation structure and philosophy, including the variable pay program and the customer-related benefits that result form UPPCO's ability to attract and retain a talented, high-performing workforce.

EXHIBITS

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Confidential Exhibit No. A-53 (KLR-1), UPPCO Compensation Plan (Administrative Only), which was either prepared by me or under my direct supervision.

PROJECTED TEST YEAR COMPENSATION & BENEFITS

Q. Please describe UPPCO's compensation structure.

A. UPPCO's compensation programs are designed to attract and retain talented, skilled, high-quality employees in a tight labor market with the necessary skills to safely and reliably serve our customers. UPPCO does this by maintaining a total compensation structure that is competitive with the compensation paid by other employers in our industry as well as other non-energy organizations in the applicable labor markets in which we operate. A substantial number of UPPCO employees are union members and represented by the international brotherhood of electrical workers, local 510. The most recent collective bargaining agreement ("CBA") took effect on April 16, 2023. The CBA negotiated competitive wages for the high-skilled, union-represented employees through April 18, 2026. The previous CBA negotiated competitive wages through April 15, 2023. For the administrative, non-represented employees including officers, the compensation structure was established to compete for and retain high-quality, talented employees in a market that includes regulated and non-regulated energy companies as well as non-energy organizations. UPPCO's compensation programs include fixed (base) pay and variable pay, both of which are reviewed at least annually to ensure our compensation programs will attract and retain a quality workforce, providing substantial value to UPPCO customers.

Q. Please describe the importance of maintaining a competitive compensation structure.

A. The Cybersecurity and Infrastructure Security Agency ("CISA"), which is referred to as America's Cyber Defense Agency, defines critical infrastructure as follows:

> *"Critical Infrastructure are those assets, systems, and networks that provide functions necessary for our way of life. There are 16 critical infrastructure sectors that are part of a complex, interconnected ecosystem and any threat to these sectors could have potentially debilitating national security, economic, and public health or safety consequences.*"[1]

As an electric utility that owns, operates and maintains significant hydroelectric and distribution infrastructure assets, UPPCO is considered part of two critical infrastructure sectors as defined by CISA: 1) the Dams Sector, and 2) the Energy Sector.

UPPCO does not have the luxury of choosing to attract and retain a skilled workforce to effectively operate systems and assets within two of America's critical infrastructure sectors – the Company must ensure that it operates competitively in our industry. By attracting and retaining a motivated and skilled workforce, the Company ensures that it has a workforce that can execute UPPCO's mission of *keeping lights on by investing responsibly in safety, reliability and people*. UPPCO's compensation structure is designed to ensure that the Company is best structured compete effectively.

Q. Does UPPCO offer any compensation programs for officers only?

[1] https://www.cisa.gov/topics/critical-infrastructure-security-and-resilience/critical-infrastructure-sectors

A. Yes, UPPCO offers a deferred compensation program for certain officers that is intended to attract and retain qualified executives by maintaining a total compensation structure that is competitive with the compensation paid by other employers in our industry and in applicable labor markets in which we operate. UPPCO is not seeking recovery of the costs of officer deferred compensation program in this proceeding.

Q. Has the Company's compensation structure materially changed since the approval of UPPCO's last general rate case, Case No. U-21286?

A. No.

Q. How are increases in base pay determined?

A. For represented employees, base pay increases annually by the amount negotiated in the CBA. Administrative, non-represented employees, including officers, are offered the opportunity for an annual merit increase. Merit increases are based on performance measures set by and evaluated by the employees and their supervisor/manager. Performance measures are based on business objectives that are determined each year. Administrative, non-represented positions may also be evaluated annually for reclassifications and equity adjustments to account for changes in job duties, internal equity, and market conditions.

Q. When was UPPCO's compensation plan last updated?

A. June 8, 2017. Please see Confidential Exhibit A-53 (KLR-1) for a copy of UPPCO's Compensation Plan (Administrative Only).

Q. Does UPPCO's compensation plan include a variable pay program?

A. Yes, UPPCO's compensation plan also includes a variable pay program with two components: i) pay-at-risk pay is based upon meeting certain key safety and operational performance metrics, and ii) incentive pay is based upon the financial performance of the Company.

Q. Which variable pay plans are included in the Projected Test Year for the purposes of this proceeding?

A. Consistent with the treatment of a substantively identical compensation program in Case No. U-21286, pay at risk pay, which does not have a financial performance qualifier, is included in the projected test year costs for the calendar year ending December 31, 2025. UPPCO is not seeking recovery of any costs relating to incentive pay or executive deferred compensation in this case.

Q. Please describe UPPCO's pay-at-risk pay.

A. UPPCO offers administrative, non-represented employees' additional performance-based compensation on an annual basis, for meeting specific non-financial safety and customer related operations metrics. This is called pay-at-risk. This pay is based upon achieving results that will have a direct impact on increased customer satisfaction, including increased distribution reliability metrics. UPPCO's pay-at-risk pay is predicated on meeting these safety and operational goals. Placing a portion of employee compensation at risk based on performance encourages employees to achieve high levels of performance, customer satisfaction, and productivity, all to the benefit of UPPCO customers. Again, no financial qualifiers are utilized in determining pay-at-risk pay.

Q. How do safety metrics benefit customers?

A. Customers directly benefit from having a safety focused, qualified, talented, and motivated utility workforce. Safety metrics benefit UPPCO customers by encouraging safety and reducing costs and inefficiencies associated with on-the-job accidents. Injuries cause higher operating expenses, which are then reflected in customer rates. The focus on employee safety is part of a larger effort to encourage a "safety culture" in which all aspects of safety, including public, customer, and employee safety become a daily part of what we do. The pay-at-risk safety metrics encourage the identification and control of hazards in the planning phases, lead to increased efficiency and lowered costs, and ultimately are a direct benefit to customers. Proactive safety reports have increased over 58% in the last four years, which has resulted in the lowest achievable rating of 0.7 of any industry for UPPCO's Experience Modification Rating ("EMR" or "MOD Rating/Factor") used to price worker's compensation premiums. Additionally, actual workers compensation costs have decreased by over 90% since 2017.

Q. How do operational performance metrics benefit customers?

A. Operational metrics benefit UPPCO's customers by encouraging an increased emphasis on improving services delivered to our customers. The metrics are designed to motivate employees to improve the Company's performance with respect to customer communication, customer service, and field service, and to maintain safe and reliable customer support, reduce the frequency and duration of planned and unplanned service interruptions, and provide continuous improvement in the quality of service provided to customers. For example, UPPCO strives to meet aggressive reliability targets, providing significant benefit to its customers. This is illustrated by UPPCO's five-year SAIDI results (excluding MEDs). UPPCO's five-year average through 2021 was, on average, 35% better than several comparable utilities in Michigan and the Midwest. Company witness Ringler provides a more detailed explanation of UPPCO's reliability statistics in his direct testimony and exhibits.

Other operational metrics are structured to focus employee attention on maximizing the customer experience, which also results in significant benefits to customers.

Q. Has there been any substantive changes to the pay-at-risk performance metrics since the approval of UPPCO's last rate proceeding in Case No. U-21286?

A. No.

Q. Please explain UPPCO's incentive pay program.

A. UPPCO provides incentive pay to administrative, non-represented employees, including executives, on an annual basis for meeting a financial goal of Earnings Before Interest, Taxes, Depreciation, and Amortization ("EBITDA"). This incentive pay is based upon achieving results that have a direct impact on managing the cost of service to customers and increasing operational efficiency. UPPCO's incentive pay utilizes the EBIDTA metric as a qualifier. Consistent with the treatment of similar expenses in Case No. U-21286, UPPCO is not seeking recovery of the costs of incentive pay in this proceeding.

Q. Does UPPCO offer any other incentive compensation programs not covered by the UPPCO Compensation Plan?

A. Yes. UPPCO offers a deferred compensation plan for certain officers. UPPCO is not seeking recovery of the costs relating to executive deferred compensation in this proceeding.

Q. Is the Company's overall compensation program, including base pay and variable pay-at-risk components, reasonable?

A. Yes. The approach used by the Company is reasonable and market-based, is consistent with industry standards, and represents well-established best practices for creating an emphasis on safety and customer focus through compensation design. The overall compensation levels are a reasonable cost of doing business and are designed to promote clear customer benefits. Linking pay to performance creates a culture of high performance and cost-consciousness, which efficiently and economically aligns employee and customer interests. UPPCO's organizational performance consistently improves by retaining highly skilled, high-performing employees and by recognizing and awarding the knowledge, skills, and experience that make them successful. Investors share in the expense of the program and bear the costs of the incentive pay and deferred compensation plans. Competitive compensation levels for employees of UPPCO is reasonable.

EMPLOYEE BENEFIT PLANS

Q. Who is eligible for UPPCO's benefit plans?

A. (i) Full-time, regular, active administrative, non-represented employees and eligible dependents; (ii) full-time, regular, active represented employees and eligible dependents; (iii) retirees who have met eligibility criteria and eligible dependents.

Q. What benefits does UPPCO offer to its active employees?

A. UPPCO offers medical, health savings account ("HSA"), prescription, medical emergency transport, cash in lieu of benefits (for employees waiving medical due to alternate group medical coverage), dental, vision, flexible spending account ("FSA"), life Insurance, accidental death and dismemberment, short-term disability, long-term disability, employee assistance program, identity theft protection, COBRA, 401(k) match, 401(k) non-elective age & service contribution (only applicable to non-pension eligible employees hired on or after April 19, 2009), pension (only applicable to employees hired prior to April 19, 2009), wellness program, holidays, vacation, vacation buy-up, sick pay, tuition reimbursement, adoption assistance, and mobile communication stipend. On a voluntary basis, employees may purchase additional employee life insurance, spouse life insurance, and child life insurance.

Q. Why does UPPCO offer these benefits?

A. Offering theses benefits allows UPPCO to attract and retain a qualified and motivated workforce in a tight labor market that includes regulated and non-regulated energy companies as well as non-energy organizations. UPPCO evaluates benefits annually and compares cost and benefit design with the market. UPPCO's ability to attract and retain talented employees provides benefits to our customers in the form increased quality of service.

Q. Have the benefits and/or benefits programs substantively changed since the approval of UPPCO's last general rate case, in Case No. U-21286?

A. No.

Q. Describe the medical benefits.

A. UPPCO offers two fully insured medical plan options underwritten by Blue Cross Blue Shield of Michigan ("BCBSM"). Prescription coverage is included with both options. The first option is a High Deductible Health Plan ("HDHP"). By offering a HDHP, UPPCO is also able to distribute tax-sheltered dollars into a Health Savings Account ("HSA") for employees. By depositing into employee HSAs, the UPPCO plan remains competitive within the market and encourages employees to make good medical consumer decisions. The second option is a traditional Preferred Provider Organization ("PPO") plan. The PPO plan offers employees the option for the first dollar coverage through traditional copays at time of service, such as office visit & prescription drug copays and lower deductible requirements. The PPO Plan is not eligible for HSA contributions; however, it allows employees to elect a plan that distributes copays throughout the year. Employees enrolled in the UPPCO medical benefits are also enrolled in medical emergency transport coverage underwritten by MASA Medical Transport Solutions. By adding this coverage to the medical benefits, employees are protected from surprise emergency medical bills and ensures compliance with emergency medical billing regulations.

Q. Describe the Prescription Benefits.

A. Prescriptions are integrated with the medical plans underwritten by BCBSM.

Q. Does UPPCO pay the entire cost of the premium for medical and prescription coverage for eligible employees and their dependents?

A. No, UPPCO and eligible employees share the cost of the premiums for medical and prescription coverage. All employees pay 20% of the premiums, including employees represented by the Union as negotiated in the CBA that took effect April 16, 2023.

Q. Describe the Dental Benefits.

A. UPPCO offers dental coverage that is separate from the medical plan and is underwritten by Delta Dental of Michigan. The plan is a traditional indemnity PPO design.

Q. Does UPPCO pay the entire cost of the premium for dental coverage for eligible employees and their dependents?

A. No, UPPCO and eligible employees share the cost of the premiums for dental coverage. All employees pay 40% of the premiums, including represented employees as negotiated in the CBA that took effect April 16, 2023.

Q. Describe the vision benefits.

A. UPPCO offers vision coverage that is separate from the medical plan and is underwritten by VSP, purchased through BCBSM. UPPCO offers two levels of coverage, basic and premier. By offering two levels of coverage, employees have the option to choose less costly coverage, which is less costly for the employee and UPPCO.

Q. Does UPPCO pay the entire cost of the premium for vision coverage for eligible employees and their dependents?

A. No, UPPCO and eligible employees share the cost of the premiums for vision coverage. All employees pay 50% of the premiums for both the basic and premier plans, including employees represented by the Union as negotiated in the CBA that took effect April 16, 2023.

Q. Describe the Flexible Spending Account Benefit.

A. UPPCO offers a flexible spending account ("FSA") benefit that allows eligible employees to redirect a certain amount of money per year from their pay into a limited use health care FSA (if enrolled in the HDHP medical with HSA plan), a health care FSA (if not enrolled in the HDHP medical with HSA plan), or a dependent care FSA that are exempt from Federal, State, and Social Security ("FICA") taxes. The most that can be allocated into these accounts is tied to the limits set annually by the IRS.

Q. Is there a cost to UPPCO for providing this benefit?

A. Yes. While UPPCO does not contribute to these plans on behalf of participating eligible employees, the administrative cost of the plan including an annual fee of $250 and a monthly fee of $4.90 per active employee are paid by UPPCO.

Q. Describe the identity theft protection Benefit.

A. UPPCO offers identity theft protection to eligible employees. There are two levels of benefits to choose from, premier and premier plus. Benefits are underwritten through Norton Lifelock Benefit Solutions.

Q. Is there a cost to UPPCO for providing this benefit?

A. Yes. UPPCO pays the cost for the employee only premier plan coverage level for eligible employees. Employees pay 100% of the dependent cost and the difference to buy-up to the premier plus coverage level.

Q. Describe the life insurance benefit.

A. UPPCO offers basic life, supplemental life and dependent life insurance underwritten by Prudential Life Insurance Company.

Q. Is there a cost to UPPCO for providing basic life insurance?

A. Yes. UPPCO pays 100% of the monthly cost of basic life insurance for eligible employees.

Q. Is there a cost to UPPCO for providing employee-only supplemental life insurance?

A. No, there is no cost to UPPCO for providing this benefit. The rates eligible employees pay for employee only supplemental life coverage is based on the amount of coverage they select and their age.

Q. Is there a cost to UPPCO for providing spouse supplemental life insurance?

A. No, there is no cost to UPPCO for providing this benefit. The rates eligible employees pay for spouse supplemental life coverage is based upon the amount of coverage selected.

Q. Is there a cost to UPPCO for providing child(ren) supplemental life insurance?

A. No, there is no cost to UPPCO for providing this benefit.

Q. Describe the accidental death and dismemberment benefit.

A. UPPCO offers accidental death and dismemberment ("AD&D") underwritten by Prudential Life Insurance Company. Eligible employees receive Company-sponsored AD&D insurance benefits and have the option to purchase additional AD&D insurance on themselves and their qualified dependents. AD&D provides benefits in the event of an accidental injury that results in the death or dismemberment of a covered person.

Q. Is there a cost to UPPCO for providing basic AD&D coverage?

A. Yes, UPPCO pays 100% of the cost for eligible employees.

Q. Is there a cost to UPPCO for providing supplemental AD&D?

A. No, there is no cost to UPPCO for providing this benefit. The rates eligible employees pay are based on the amount of coverage selected.

Q. Describe the short-term disability benefit.

A. UPPCO offers short-term disability underwritten by Prudential Life Insurance Company. In the event illness or injury prevents employees from being able to work, UPPCO provides disability benefits to ensure the continuation of their income. Eligible employees are automatically enrolled and covered by both short-term and long-term disability benefits. This benefit is for employees only. It does not pay for a spouse or child disability. This benefit is for employees only. It does not pay for a spouse or child disability. The benefit for administrative, non-represented employees is 60% of weekly earnings, up to $2,000 weekly. Represented employees receive a $500 weekly benefit in accordance with the CBA.

Q. Is there a cost to UPPCO for providing this benefit?

A. Yes, UPPCO pays 100% of the premium cost for eligible employees.

Q. Describe the long-term disability benefit.

A. UPPCO offers long-term disability, underwritten by Prudential Life Insurance Company. If an employee is unable to return to work for an extended period, typically defined as beyond short-term disability benefits and in some cases longer, UPPCO provides long-term disability benefits. This benefit is for employees only. It does not pay for a spouse or child disability. The benefit for administrative, non-represented employees is 60% of monthly earnings, up to $15,000 monthly. Represented employees receive a 66.66% of monthly earnings, up to $5,000 monthly in accordance with the CBA.

Q. Is there a cost to UPPCO for providing this benefit?

A. Yes, UPPCO pays 100% of the premium cost for eligible employees.

Q. Describe the employee assistance program Benefit

A. The employee assistance program ("EAP") offers professional support and direction to resolving employees' problems or concerns. The program also provides both self-help resources online, as well as confidential counseling for issues.

Q. Is there a cost to UPPCO for providing this benefit?

A. Yes, UPPCO pays 100% of the cost for eligible employees.

Q. Describe the COBRA benefit.

A. COBRA is the Consolidated Omnibus Budget Reconciliation Act and allows eligible employees and/or their covered dependents to extend medical, dental, and/or vision coverage beyond the date on which eligibility would normally end. As a large employer with more than 20 full-time employees, UPPCO is legally required to offer COBRA if a qualifying event occurs that causes a loss of coverage under the group health plans. To ensure the COBRA benefits are managed according to the law and follow any changes that may happen under the law, UPPCO contracts with a third-party to distribute notices and manage billing.

Q. Is there a cost to UPPCO for providing this benefit?

A. Yes, the cost to UPPCO for providing third-party COBRA coverage is an administrative fee of approximately $175 per month.

Q. Describe the 401(k) matching plan benefit.

A. Key features of the 401(k) matching plan include:

Company Matching Contribution – as required by the CBA, represented employees hired prior to April 19, 2009, UPPCO matches of 50% on the first 6.5% of eligible compensation that employees contribute to the 401(k) plan. The match occurs automatically, and employees are always 100% vested in the Company match.

Company Matching Contribution – For administrative, non-represented employees and represented employees, as required by the CBA, hired on or after April 19, 2009, UPPCO matches dollar for dollar the first 5% of eligible compensation that employees contribute to the 401(k) plan. The match occurs automatically, and employees are always 100% vested in the Company match.

Age and Service Contribution – For administrative, non-represented employees and represented employees, as required by the CBA, hired on or after April 19, 2009, UPPCO makes a non-elective contribution to the employees 401(k) plan. The amount employees receive depends on how much compensation they were paid during the year as well as the group to which they are assigned. Groups consist of the sum of participants age and full years of vesting service as of the end of each payroll period which end in the plan year for which the contribution is made. Percentages listed are expressed as a percentage of total eligible compensation for all participants eligible for the allocation:

0-34 = 3%

35-49 = 4%

50-64 = 5%

65-79 = 6%

80 and above = 7%

Q. Describe the pension benefit

A. UPPCO offers a two-part traditional pension benefit to eligible employees. Part A consists of administrative, non-represented employees hired prior to January 1, 2008 or represented employees who transferred to an eligible administrative position between January 1, 2009 and December 31, 2012. The plan was closed January 1, 2008, and benefits were frozen as of December 31, 2017, however interest credits continue to apply. Part A beneficiaries may elect a lump-sum benefit or monthly annuity payment.

Part B is closed to new entry and consists of represented employees hired prior to April 19, 2009. Employees enrolled in Part B Pension Benefits continue to accrue benefit as long as they remain employed in an eligible position. Part B beneficiaries receive benefits in the form of a monthly annuity payment.

Q. Describe the wellness program benefit.

A. UPPCO offers a formal wellness program to all regular full-time employees of UPPCO and their spouses. The wellness program is designed to encourage preventive care through completing an annual health exam to catch potential health concerns early, before becoming a major concern. Employees and their spouses are also eligible for reimbursements for wellness related activities and equipment.

Q. Is there a cost to UPPCO for providing this benefit?

A. The cost for providing this benefit is in the form of an HSA contributions or payroll contributions received by the employee based on the employee's medical plan enrollment. Employees and spouses are eligible to receive $250 each for the completion of an annual physical. Employees and spouses are eligible to receive up to $250 each for reimbursement of wellness related activities and/or equipment. They may also access BCBSM's Health and Wellness site through their BCBSM member-portal. Access to the site and tools is $18 per member (employee-spouse) per year. UPPCO only experiences costs for the health coaching or tobacco cessation as employees engage in the programs. For lifestyle coaching, the pricing is $300 per employee or eligible family member who uses the program.

Q. Describe the tuition reimbursement benefit.

A. This benefit is available to any active, regular full-time employee. UPPCO recognizes the value of continuing education and career development. Tuition reimbursement is designed to help the Company improve and develop the knowledge and skills of its employees and to help employees pursue UPPCO career related learning opportunities. To engage in this program, employees must apply for consideration through their leader and HR, to ensure the education program meets the outline of the program as well as benefits their career within UPPCO. Employees will be reimbursed for tuition expenses, textbooks and lab fees for any approved course. Reimbursements will be made, minus and ineligible expenses, consistent with the Internal Revenue Service ("IRS") regulations pertaining to tax excludability for Educational Assistance Programs. Coursework must be related to the employee's current position or a reasonable promotional opportunity within the Company or included as part of a degree program meeting this requirement. Employees are eligible to be reimbursed per calendar year maximum of $5,250 for undergraduate or non-degree courses and $8,000 for graduate courses with amounts exceeding the annual IRS tax-excludable limits taxed as wages.

Q. Describe the adoption assistance benefit.

A. This benefit applies to any active regular full-time employees of UPPCO. UPPCO recognizes that the adoption process can place a burden on an employee, both with time constraints and finances. To show its commitment to employee families, UPPCO will share some of this burden with employees who adopt. The maximum payment per adoption is $3,000, with an annual limit of $3,000 per employee.

Q. Please describe the cash-in-lieu of benefits program.

A. This benefit applies to employees waiving UPPCO medical coverage due to enrollment in an alternate group health insurance program, such as military coverage or coverage through a spouse or parent. UPPCO recognizes the need to provide a form of benefit to all eligible employees. By offering a cash-in-lieu program, all employees realize a form a medical benefit. The monthly benefit is $400 or $184.62 bi-weekly per participating employee, which is significantly less than the cost of medical premiums.

Q. Please describe the paid time away programs.

A. UPPCO offers paid holidays, vacation time, sick time, Family Medical Leave ("FMLA"), and personal time. Paid holidays for represented employees are negotiated in the CBA. Paid holidays for Administrative, non-represented employees are New Year's Day, Good Friday, Memorial Day, July 4th, Labor Day, Thanksgiving and the Friday after, Christmas Eve, and Christmas Day. Vacation time is offered to employees on a sliding scale based on years of service and is negotiated in the CBA for Represented employees. All employees may purchase up to two weeks of additional vacation through payroll deductions.

Q. What benefits does UPPCO offer to its retirees?

A. Medical (outlined by the CBA or Retiree Medical Care Credit Program), dental (closed to new entrants and only applicable to some retirees), vision, life insurance (closed to new entrants), and pension payments (closed to new entrants).

Q. Describe the medical benefits available to retirees.

A. There are three separate medical plans available to retirees depending on their age and plan availability at the time of retirement. Retirees up to age 65 are offered a traditional

PPO plan with prescription drugs, underwritten by BCBSM. Retirees over the age of 65 or enrolled in Medicare Disability are offered Medicare Advantage and Medicare Prescription Drug Plan Coverage ("MA", "PDP") plan. There is one small segment of retirees, enrolled in a closed Medicare Advantage and Medicare Prescription Drug Plan mirroring a Medigap plan. The Medicare Advantage plans are underwritten by BCBSM and the prescription drug plans are underwritten by Humana.

Q. Does UPPCO pay the entire cost of medical benefit coverage for retirees?

A. Generally, no. A limited number of formerly represented retirees have the option of electing three years of free coverage as part of their retirement package. There are a very limited number of formerly represented retirees that retired form UPPCO when the Company sold the Presque Isle Power Plant. Part of the sale agreement allowed those individuals to defer three years of free coverage until they needed it. Current represented employees may also elect up to three years of free coverage upon retirement. Once the three-year free coverage period has ended, the formerly represented retiree is responsible for 50% of their medical premiums.

Administrative, non-represented employees who have attained age 45 accrue Retiree Medical Care Credits ("RMCC"). Vesting occurs in their RMCC account once they have completed three years of service after attaining age 45. Credits can be used to pay for retiree medical. Former administrative, non-represented retirees may elect to use RMCCs to share in the monthly premium cost of retiree medical in 25% increments. Once the credits have been exhausted, UPPCO no longer pays for any portion of the premiums.

Q. Describe the dental benefits available to retirees.

A. The dental benefit available to retirees in the same as that available to active represented and non-represented administrative employees, with the exception that the retirees do not have an orthodontia benefit.

Q. Does UPPCO pay the cost of dental coverage for retirees?

A. UPPCO pays 50% of the cost for dental coverage for pre-2001 retirees. Post-2001 retirees and dependents are responsible for 100% of the cost of coverage.

Q. Describe the vision benefits available to retirees.

A. The vision benefit available to retirees is the same as that available to active represented and administrative, non-represented employees.

Q. Does UPPCO pay the cost of vision coverage for retirees?

A. No. Retirees are responsible for 100% of the cost of vision coverage.

Q. Describe the life insurance benefit available to retirees.

A. This benefit is a closed benefit. A closed segment of administrative, non-represented employees and represented employees retiring prior to May 1, 2018 are eligible for retiree life insurance. The maximum life insurance benefit payable under the plan is $15,000.

Q. Does UPPCO pay the cost of life insurance for retirees?

A. Yes. UPPCO is responsible for 100% of the cost of the plan. The cost equates to $6.48 per $1,000 of coverage.

Q. Is there anything else you would like to share regarding compensation and benefits?

A. Yes. Physically and mentally healthy employees improve productivity. A healthy workforce reduces absenteeism, sustains employee commitment to top performance, which improves productivity and ultimately, customer satisfaction. UPPCO has continued to evolve its compensation and benefits programs to improve employee's overall well-being and to remain competitive for attraction and retention of employees, while continuing to implement cost-savings measures. By implementing cost-saving measures and actively managing the plans, UPPCO has been able to minimize external cost impacts to the organization, and in turn to the UPPCO ratepayers. UPPCO has realized premium decreases in three of the last six years, with increases of less than 5% in two of the last six years.

Additionally, wherever possible, UPPCO has contracted with benefit providers that are Michigan-based companies. They understand our unique challenges in coverage across our service territory and in the State of Michigan in general with retirees across the United States. For example, the medical plans are provided by BCBSM, and dental is provided by Delta Dental of Michigan. UPPCO has also partnered with benefits brokers, VAST and Health Insurances Services (HIS). When UPPCO originally partnered with VAST, they were an independent Upper Michigan based insurance agency. Since the partnership, VAST was purchased by Acrisure. VAST maintains their original VAST DBA and provides a valuable partnership, familiar with Michigan insurance rules and the unique territory of Michigan insurance competition. In 2020, VAST and UPPCO partnered with HIS to manage the retiree medical benefits. HIS is a Michigan based brokerage firm specializing in retiree medical benefits. These providers offer benefit options that meet our financial and coverage needs.

Q. Are UPPCO's compensation and benefits plans reasonable and prudent, and should the Company be allowed to recover the costs of same programs in their entirety?

A. Yes, the purpose of UPPCO's compensation and benefits is to attract and retain talented, high-quality employees in a tight labor market with the necessary skills to serve our customers safely and reliably. The labor market is tight for everyone; however, it is even more challenging for UPPCO due to the remote nature of the areas we serve. In some cases, the labor market for the skills we need requires us to compete for talent with much larger utilities who are in much more desirable areas. UPPCO is also negatively impacted by the housing market and lack of daycare options for employees with children. With relatively few homes on the market for sale and the increased cost to buy homes are very real barriers for UPPCO in attracting talent. Finding reliable and affordable daycare in the areas we serve is a significant challenge. Because of these challenges, UPPCO must offer competitive pay and benefits to ensure we attract and retain the talent necessary to serve our customers.

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
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In the matter of the application of	)	
UPPER PENINSULA POWER COMPANY	)	
for authority to increase its rates for the generation	)	Case No. U-21555
and distribution of electricity and other relief.	)	
	)	

DIRECT TESTIMONY AND EXHIBITS OF

NICOLE E. BELL

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

March 21, 2024

Q. Please state your name, business address, and the name of your employer for the record.

A. My name is Nicole E. Bell. My business address is 18494 Canal Road, Houghton, Michigan 49931. I am employed by Upper Peninsula Power Company ("UPPCO" or the "Company").

Q. Please describe your job responsibilities.

A. My title is Regulatory Analyst within the Regulatory Affairs department. My responsibilities in this role include a wide variety of issues touching several aspects of UPPCO's business, including tariff administration, Renewable Portfolio Standard ("RPS") compliance analysis, sales and peak demand forecasting, rate design and revenue analysis, among other related duties.

Q. Briefly describe your educational background and applicable professional experience.

A. I graduated from the Community College of the Air Force in 2013 with an Associate of Applied Science in Weather Technology. I graduated from American Military University in 2016 with a Bachelor of Science in Environmental Science. I graduated from Grand Canyon University in 2021 with a Master's in Business Administration. In January 2011, I entered employment with the United States Air Force (USAF) as a Weather Specialist, tasked with the observing, recording, forecasting, and dissemination of weather data and information to military installations throughout the United States. In January 2015, I completed my enlistment in the USAF and began employment with the Tucson Electric Power Company ("TEPC") as a Renewable Energy Forecaster and Trading Analyst in the

Wholesale Marketing and Renewables departments of TEPC. My responsibilities in this position included the forecasting and analysis of renewable resource output and availability, the updating and maintaining of TEPC's renewable resource forecasting models, and other analysis of the department's generation resources, including analysis of transactions between TEPC and its counterparties. I cross-trained in several different positions throughout the Wholesale Marketing department, where I completed tasks related to the scheduling of power purchases and sales, creation and monitoring of transaction tags, creation and monitoring of transmission reservations, and the conducting of daily communication between counterparties. In January 2020, I left my employment with TEPC. I began employment with UPPCO in March 2020 as a Regulatory Analyst within the Regulatory Affairs department.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC")?

A. Yes. I have provided testimony in several cases before the Commission. Recent notable examples include the following proceedings on behalf of UPPCO: Case No. U-21286 (General Rate Case), Case No. U-21059 (2022 PSCR reconciliation), Renewable Energy reconciliation cases, most recently, Case Nos. U-21356, U-21201, and U-21013, and Case No. U-21433 (2024 PSCR Plan).

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present analysis and discussion of the following topics in support of the Company's request for rate relief in this proceeding:

1. The development of the Company's current electric sales and peak demand forecast for the period 2025 – 2029.
2. The Company's proposed rate design, pursuant to the results of the Company's Cost of Service Study ("COSS") sponsored by Company Witness Stocking.
3. Adjustment of the Company's existing Distributed Generation ("DG") program, necessary to comply with Section 173 of PA 235.
4. Projected participation in the Company's existing Residential Income Assistance Program ("RIA").

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following Exhibits:

I. Exhibit A-5, Schedule E1.1 (NEB-1):
II. Exhibit A-5, Schedule E1.2 (NEB-2):
III. Exhibit A-5, Schedule E1.3 (NEB-3):
IV. Exhibit A-10, Schedule E1.1 (NEB-4):
V. Exhibit A-10, Schedule E1.2 (NEB-5):
VI. Exhibit A-10, Schedule E1.3 (NEB-6):
VII. Exhibit A-10, Schedule E2.1 (NEB-7):
VIII. Exhibit A-10, Schedule E2.2 (NEB-8):
IX. Exhibit A-11, Schedule F2 (NEB-9):
X. Exhibit A-11, Schedule F3 (NEB-10):
XI. Exhibit A-11, Schedule F4 (NEB-11):
XII. Exhibit A-11, Schedule F5 (NEB-12):

Q. Were these Exhibits prepared by you or under your direction?

A. Yes, they were.

Sales and Peak Demand Forecast

Q. Please describe Exhibit A-5, Schedules E1.1, E1.2, E1.3.

A. Exhibit A-5, Schedule E1.1 (NEB-1) provides an annual summary of historical service area sales by major customer class for the years 2019 – 2023. This exhibit also summarizes company use and distribution loss kilowatt-hours (“kWh”), and sums to total system output.

Exhibit A-5, Schedule E1.2 (NEB-2) provides an annual summary of historical bundled service sales by major customer class for the years 2019 – 2023. This exhibit also summarizes company use and distribution loss kWh, and sums to total system output.

Exhibit A-5, Schedule E1.3 (NEB-3) provides an annual summary of historical Alternative Electric Supplier (“AES”) sales by major customer class for the years 2019 – 2023.

Q. Please describe Exhibit A-10, Schedules E1.1, E1.2, E1.3, E2.1, and E.2.2.

A. Exhibit A-10, Schedule E1.1 (NEB-4) provides an annual summary of projected service area sales by major customer class for the years 2025 – 2029. This exhibit also summarizes company use and distribution loss kWh, and sums to total system output.

Exhibit A-10, Schedule E1.2 (NEB-5) provides an annual summary of projected bundled service sales by major customer class for the years 2025 – 2029. This exhibit also summarizes company use and distribution loss kWh, and sums to total system output.

Exhibit A-10, Schedule E1.3 (NEB-6) provides an annual summary of projected AES sales by major customer class for the years 2025 – 2029.

Exhibit A-10, Schedule E2.1 (NEB-7) provides an annual summary of total service area system output, maximum demand, and average system load factor for years 2019 – 2029.

Exhibit A-10, Schedule E2.2 (NEB-8) provides an annual summary of bundled system output, maximum demand, and average system load factor for years 2019 – 2029.

Q. Please explain how the Company developed its sales forecast for the 12 month projected test period ending December 31, 2025 ("Projected Test Year").

A. The Residential forecast utilizes a regression model that includes seasonal customers and sales. The historical period utilized as a basis for the projection is April 1, 2013 through July 31, 2023. The regression model utilizes seasonal, weather-related, and autoregressive variables to project average residential customer usage. The product of the customer forecast yields the values depicted in Exhibit A-10, Schedule E1.2 (NEB-5).

The Commercial forecast utilizes a regression model that includes sales to commercial customers within the service territory. The historical period utilized as a basis for the projection is January 1, 2014, through July 31, 2023. The regression model utilizes seasonal, weather-related, and autoregressive variables to project average commercial customer usage. The product of the customer forecast yields the commercial class values depicted in Exhibit A-10, Schedule E1.2 (NEB-5).

The Industrial forecast utilizes a simple moving average method of forecasting that uses historical data from August 1, 2020 – July 31, 2023. The model averages the usage of Industrial customers within the service territory over the last three years to determine a projection for the test year. The product of the customer forecast yields the Industrial class values depicted in Exhibit A-10, Schedule E1.2 (NEB-5).

The Company Use forecast utilizes a simple moving average method of forecasting that uses historical data from August 1, 2019 – June 30, 2023. The model averages the Company's usage over the last four years to determine a projection for the test year. The product of the customer forecast yields the Company Use values depicted in Exhibit A-10, Schedule E1.2 (NEB-5).

The Street Lighting forecast utilizes a simple moving average method of forecasting that uses historical data from July 1, 2020 – June 30, 2023. The model averages the Street Lighting usage over the last three years to determine a projection for the test year. The product of the customer forecast yields the Street Lighting values depicted in Exhibit A-10, Schedule E1.2 (NEB-5).

Q. How did the Company project total AES customer sales throughout the forecast period?

A. During calendar year 2021, the Company moved 33 customers to its AES program. During calendar year 2022 and 2023, participation in the Company's AES program has exceeded the ten percent cap on retail choice customer participation dictated by the governing statute. For the purposes of projecting the applicable rate class volumes for this proceeding, the Company assumes that total AES sales and demand will remain static at current levels, as the customer migrations that occurred during calendar year 2021 are appropriately reflected in the subsequent years' AES customer sales. The Company assumes that, for the projected time periods within the purview of this proceeding, the composition of customers receiving power supply service from an AES will remain unchanged.

Q. Are the effects of Energy Waste Reduction ("EWR") included in the sales forecast presented here?

A. Yes, the effects of EWR on total sales in each applicable rate category are included in the forecast presented in this proceeding and are implicitly assumed to continue at average historical trend levels throughout the forecast period.

Q. Please explain how the total company demand forecast was developed for the projected test year.

A. Peak demand is forecasted using a regression analysis of historical peak kilowatt ("kW") to monthly kWh sales, along with weather and seasonal explanatory variables.

Q. Please explain the procedures used to develop fixed charge counts for the projected test year.

A. The fixed charge forecasts for the Residential, Commercial, and Industrial sectors were developed using a 12-month analysis of actual billed historical data at the rate schedule level, including both monthly fixed charges and lamp counts. The 12-month historical period used in the analysis was January 2023 – December 2023. This analysis produced a known and measurable outlook of fixed charge billing determinants for rate schedules A-1, AH-1, C-1, H-1, P-1, CP-U (Secondary, Primary, and Transmission), WP-3, Z-3, SL-3, SL-5, and SL-6. The fixed charge billing determinants are assumed to be static between the 2023 historical period and the projected test year.

Q. What weather and temperature assumptions were made in the development of the Company's sales and peak demand projection?

A. UPPCO used a 10-year average of actual monthly weather observations at KI Sawyer International Airport, as reported by the National Oceanic and Atmospheric

Administration (“NOAA”) between the years of 2014 – 2023 as the basis for assumed future weather characteristics utilized in the forecast.

Q. Please describe the Company’s kWh sales projection for the projected test year.

A. As evidenced by Schedule E1.2 of Exhibit A-10 (NEB-5), the Company projects a total bundled sales requirement of 610,084,767 kWh. This projection does not include projected sales to AES customers, nor does it include total projected sales to the RTMP rate schedule.

Q. What is the total projected test year sales utilized as the basis for rate design in this proceeding?

A. The sales projection used as a basis for rate design in this proceeding totals 571,184 MWh. This value does not include sales made pursuant to the RTMP tariff and is only partially inclusive of sales made to customers participating in the Company’s AES program, due to the nature of distribution rate billing to AES customers taking service under the Company’s CP-U and WP-3 tariffs.

Proposed Rate Design

Q. Please describe Exhibit A-11, Schedule F2 (NEB-9).

A. Exhibit A-11, Schedule F2 (NEB-9) provides a summary of revenues at current and proposed rates for each rate schedule and calculates the net percentage increase (decrease) for the 12-month period ending on December 31, 2025.

Q. Please describe Exhibit A-11, Schedule F3 (NEB-10).

A. Exhibit A-11, Schedule F3 (NEB-10) provides a detailed summary of proposed rates by rate schedule for the 12-month period ending on December 31, 2025.

Q. Please describe Exhibit A-11, Schedule F4 (NEB-11).

A. Exhibit A-11, Schedule F4 (NEB-11) calculates average bills at current and proposed rates by rate schedule for a range of usage levels, calculates the percentage increase (decrease) comparison between average bills at each rate and usage level, and calculates the average rate at each usage level for the 12-month period ending on December 31, 2025.

Q. Please describe Exhibit A-11, Schedule F5 (NEB-12).

A. Exhibit A-11, Schedule F5 (NEB-12) contains redline versions of the tariff sheets consistent with the Company's proposed rate design for the 12-month period ending on December 31, 2025.

Q. What will you be addressing in connection with UPPCO's proposed rate design?

A. I will address the following items related to rate design.

Allocation of Rate Increases, informed by the UPPCO COSS sponsored by Company witness Stocking;

1. Rate Design for the A-1 Residential Rate Schedule.
2. Rate Design for the AH-1 Residential Heating Rate Schedule.
3. Rate Design for the C-1 General Service Rate Schedule.
4. Rate Design for the H-1 Commercial Heating Rate Schedule.
5. Rate Design for the P-1 Light and Power Rate Schedule.

6. Rate Design for the CP-U Rate Schedule.
7. Rate Design for the WP-3 Rate Schedule.
8. Rate Design for the RTMP Rate Schedule.
9. Rate Design for the SL-3, SL-5, & SL-6 Rate Schedule.
10. Rate Design for the Z-3 Rate Schedule.

Q. What principles did the Company rely on when developing its rate design proposal?

A. The Company relies on a fully allocated, embedded COSS as the guiding principle for determination of revenue requirements of each individual rate schedule. The UPPCO's COSS is sponsored by Company witness Stocking. Both embedded and marginal costs should be used as guidance in rate design.

In any place that the COSS recommends a substantial change in rates, the change may be moderated to incorporate a reasonable amount of rate stability. The Company recognizes that should any rate schedule experience a significant shift in electric rate revenue requirement, the overall rate proposals may need to be revised.

With respect to, and as reflected in Exhibit A-11, Schedule F1 (EWS-3) sponsored by Company witness Stocking, the projected test year COSS indicates that UPPCO's present customer charges in the Residential and small Commercial classes are inadequate to recover the customer cost component. As reflected on Schedule F3 of Exhibit A-11, UPPCO has incorporated customer charges consistent with Exhibit A-11, Schedule F1 (EWS-3).

Lastly, rate design should reflect cost of service to the extent practical.

Q. Please describe how revenue credits will be applied to the Company's proposed rate design.

A. The Company's COSS is solved to the total revenue deficiency prior to application of the operating income adjustments. Therefore, these adjustments must be applied within the rate design process, yielding rates designed to recover the net revenue deficiency shown on Line 76 of pages 6-8 of Exhibit A-11, Schedule F1.

Q. Do UPPCO's proposed rates generally comport with the customer class level results of the projected test year COSS?

A. Yes, they do. The Company has identified the relationship between similar customer classes within the total customer classification and solved the entire group to the total required revenue. As a consequence of this method, some cross-subsidization amongst rate schedules will persist; however, this method attempts to mitigate any significant rate impact to any one rate schedule and ensures that the rates designed for each customer grouping will recoup the required revenues.

Q. Please describe UPPCO's proposed rate design for the A-1 rate schedule for the 12-month period ending on December 31, 2025.

A. As evidenced by line 79, page 6 of Exhibit A-11, Schedule F1 (EWS-3) presented by Company witness Stocking, the current rate levels within the A-1 schedule are forecasted to under-recover the revenues required for this rate schedule by 10.22%. UPPCO's proposed rate design for A-1 derives a Service Charge of $19.00 per month, and a total volumetric energy rate of $0.13875 / kWh. The details related to the proposed rate design calculation for the A-1 schedule are shown in Exhibit A-11, Schedule F3 (NEB-10).

Q. Please describe UPPCO's proposed rate design for the AH-1 rate schedule for the 12-month period ending on December 31, 2025.

A. As evidenced by line 79, page 6 of Exhibit A-11, Schedule F1 (EWS-3), the current rate levels within the AH-1 schedule are forecasted to under-recover the revenue requirement for this rate schedule by 40.65%. UPPCO's proposed rate design for AH-1 derives a Service Charge of $19.00 per month, total energy rate of $0.13875 for June – September, a total energy rate of $0.13875 for all kWh less than 500 kWh during the heating season, and a total energy rate of $0.06937 for all kWh greater than 500 kWh during the heating season. The details related to the proposed rate design calculation for the AH-1 schedule are shown in Exhibit A-11, Schedule F3 (NEB-10).

Q. Were rate schedules A-1 and AH-1 solved concurrently, as described above?

A. Yes, they were.

Q. Please describe the relationship assumed between A-1 and AH-1 used to design rates for these two categories concurrently.

A. A-1 and AH-1 customers are largely identical, except for AH-1 customers who heat their homes by electric sources. As such, there is little difference between customers within these rate schedules during the summer months. In light of this commonality, for purposes of the proposed rate design in this proceeding, the following relationships were established.

- Service Charge is equal between rate schedules,
- Distribution Energy Charge is equal, with the exception of AH-1 usage greater than 500 kWh during the heating season, which equals 50% of the standard distribution energy charge.
- Power Supply energy charge is equal throughout all rate schedules and usage tranches. Since UPPCO procures approximately 80% of its total retail energy obligations through wholesale purchase transactions, it is equitable to charge AH-1 customers a uniform power supply rate. An exception to this are AH-1 customers with usage greater than 500 kWh during the heating season, where rates are applied equal to 50% of the standard power supply energy charge.

Q. What is the Company's justification for increasing the Residential class Service Charge?

A. As discussed earlier in my testimony, the Company includes the cost of distribution service laterals, metering, meter reading, and customer account and service cost components to inform the proper fixed customer charge. As discussed by Company witness Stocking, and as outlined by Exhibit A-33 (EWS-6), this practice is consistent with prior Commission direction. The Company also aims to distribute costs more equitably among Residential class customers, reflecting the actual usage patterns and demands placed on the system. This approach helps mitigate the disproportionate burden on year-round residents, who often bear the brunt of maintaining infrastructure that serves both permanent and seasonal residential applications. By recovering a higher proportion of the total residential class revenue requirement through a fixed charge, the Company can begin to move away from residential class subsidization effect, whereby year-round residents are subsidizing the cost to provide service to seasonal type residential premises.

Q. Please describe UPPCO's proposed rate design for the C-1 rate schedule for the 12-month period ending on December 31, 2025.

A. As evidenced by line 79, page 6 of Exhibit A-11, Schedule F1 (EWS-3), the current rate levels within the C-1 schedule are forecasted to under-recover the revenue requirement for this rate schedule by 17.56%. UPPCO's proposed rate design for C-1 derives a Service Charge of $24.00, and a total energy rate of $0.16855 per kWh. The details related to the proposed rate design calculation for the C-1 schedule are shown in Exhibit A-11, Schedule F3 (NEB-10).

Q. Please describe UPPCO's proposed rate design for the H-1 rate schedule for the 12-month period ending on December 31, 2025.

A. As evidenced by line 79, page 6 of Exhibit A-11, Schedule F1 (EWS-3), the current rate levels within the H-1 schedule are forecasted to under-recover the revenue requirement for this rate schedule by 44.98%. UPPCO's proposed rate design for H-1 derives a Service Charge of $24.00 per month, a total energy rate of $0.16855 per kWh for June – September, a total energy rate of $0.16855 for all kWh less than 1,000 kWh during the heating season, and a total energy rate of $0.08427 for all kWh greater than 1,000 kWh during the heating season. The details related to the proposed rate design calculation for the H-1 schedule are shown in Exhibit A-11, Schedule F3 (NEB-10).

Q. What is the Company's justification for increasing the Commercial class Service Charge?

A. As discussed earlier in my testimony, the Company includes the cost of distribution service laterals, metering, meter reading, and customer account and service cost components to inform the proper fixed customer charge. As discussed by Company witness Stocking and outlined by Exhibit A-33 (EWS-6), this practice is consistent with prior Commission direction. The Company also aims to distribute costs more equitably among customers in the Commercial class, reflecting the actual usage patterns and demands placed on the system.

Q. Please describe UPPCO's proposed rate design for the P-1 rate schedule for the 12-month period ending on December 31, 2025.

A. As evidenced by line 79, page 6 of Exhibit A-11, Schedule F1 (EWS-3), the current rate levels within the P-1 schedule are forecasted to over-recover the revenue requirement for this rate schedule by 8.35%. UPPCO's proposed rate design for P-1 derives a Service Charge of $50.00 per month, total demand charges of $8.92 per Kw, and a total Energy Charge of $0.04294 per kWh. The details related to the proposed rate design calculation for the P-1 schedule are shown in Exhibit A-11, Schedule F3 (NEB-10).

Q. Please describe UPPCO's proposed rate design for the CP-U rate schedule for the 12-month period ending on December 31, 2025.

A. As evidenced by line 79, page 7 of Exhibit A-11, Schedule F1 (EWS-3), the current rate levels within the CP-U schedule are forecasted to under-recover the revenue requirement for this rate schedule by 61.21% in CP-U Secondary, under-recover the revenue requirement for this rate schedule by 51.5% in CP-U Primary, and under-recover the revenue requirement for this rate schedule by 37.99% in CP-U Transmission.

UPPCO's proposed rate design for CP-U Secondary derives a Service Charge of $500.00 per month, total firm demand charges of $8.21 per kW, total interruptible demand charges of $8.21 per kW, total customer demand charge of $7.80 per kW, an on-peak energy charge of $0.08750 per kWh, and an off-peak energy charge of $0.05689 per kWh.

UPPCO's proposed rate design for CP-U Primary derives a Service Charge of $650.00 per month, total firm demand charges of $6.81 per kW, total interruptible demand charges of $6.81 per kW, total customer demand charge of $6.47 per kW, an on-peak energy charge of $0.08435 per kWh, and an off-peak energy charge of $0.05483 per kWh.

UPPCO's proposed rate design for CP-U Transmission derives a Service Charge of $1,500.00 per month, total firm demand charges of $3.08 per kW, total interruptible demand charges of $3.08 per kW, total substation transformer capacity charge of $1.04 per kVA, an on-peak energy charge of $0.08126 per kWh, and an off-peak energy charge of $0.05282 per kWh. The details related to the proposed rate design calculation for the CP-U schedule are shown in Exhibit A-11, Schedule F3 (NEB-10).

Q. Please describe UPPCO's proposed rate design for the WP-3 rate schedule for the 12-month period ending on December 31, 2025.

A. As evidenced by page 7 of Exhibit A-11, Schedule F1, the current rate levels within the WP-3 rate schedule are forecasted to under-recover the revenue requirement for this schedule by 17.88%. UPPCO's proposed rate design for the WP-3 schedule derives a Service Charge of $1,500.00 per month, total firm demand charges of $3.18 per kW, total interruptible demand charges of $3.18 per kW, substation transformer capacity of $1.04 per KVA, total on-peak energy charges of $0.08126 per kWh, and total off-peak energy charges of $0.05282 per kWh. The details related to the proposed rate design calculation for the WP-3 schedule are shown in Exhibit A-11, Schedule F3 (NEB-10).

Q. Were rate schedules P-1, CP-U and WP-3 solved concurrently to mitigate any significant rate increases to recover required revenues experienced by an individual rate classes?

A. Yes, they were.

Q. Please describe UPPCO's proposed rate design for the RTMP rate schedule for the 12-month period ending on December 31, 2025.

A. As evidenced by page 7 of Exhibit A-11, Schedule F1 (EWS-3), UPPCO proposes to leave rates for the RTMP class unchanged from the prior case. It is important to note that the vast majority of costs (and revenue) attributable to providing service to the RTMP class are outside the scope of this proceeding. These costs that are borne by UPPCO as a product of providing RTMP service are passed along directly to the customer and are applied as a direct offset to the PSCR related costs experienced by the Company's non-RTMP customers.

UPPCO's proposed rate design for the RTMP schedule derives a monthly customer charge of $1,000.00 per month, a demand charge of $0.41 per kW, and a scheduling charge of $1,000 per month. The details related to the proposed rate design calculation for the RTMP schedule are shown in Exhibit A-11, Schedule F3 (NEB-10).

Q. Please describe UPPCO's proposed rate design for the Street Lighting (SL-3, SL-5, and SL-6) and Outdoor Lighting rate schedules.

A. The resulting rates are outlined in page 8 of Schedule F1 of Exhibit A-11 (EWS-3).

Q. What is the bill impact to an average Residential customer as a result of the Company's proposed rate design in this proceeding for the 12-month period ending on December 31, 2025?

A. As evidenced by Schedule F4 of Exhibit A-11 (NEB-11), a residential customer, previously taking service under the A-1 tariff, consuming 500 kWh per month will receive a monthly bill of $138.57. This constitutes an increase of $16.38, or 13.41% when compared to present revenues.

Q. What is the bill impact to an average small Commercial customer as a result of the Company's proposed rate design in this proceeding for the 12-month period ending on December 31, 2025?

A. As evidenced by Schedule F4 of Exhibit A-11 (NEB-11), a C-1 customer consuming 2,500 kWh per month will receive a monthly bill of $702.56. This constitutes an increase of $122.03, or 21.02% compared to a similarly calculated bill at current rates.

Q. What is the bill impact to an average large Commercial customer as a result of the Company's proposed rate design in this proceeding for the 12-month period ending on December 31, 2025?

A. As evidenced by Schedule F4 of Exhibit A-11 (NEB-11), a P-1 customer consuming 20,000 kWh, and 55 Kw per month will receive a monthly bill of $3,224.36. This constitutes an increase of $395.18, or 13.97% compared to a similarly calculated bill at current rates.

Q. What is the bill impact to an average Industrial customer as a result of the Company's proposed rate design in this proceeding for the 12-month period ending on December 31, 2025?

A. As evidenced by Schedule F4 of Exhibit A-11 (NEB-11), a CP-U customer consuming 480,000 kWh, and 1,260 kW per month will receive a monthly bill of $49,639.09. This constitutes an increase of $13,563.69, or 27.32% compared to a similarly calculated bill at current rates.

Q. What is the bill impact to an average Street Lighting customer as a result of the Company's proposed rate design in this proceeding for the 12-month period ending on December 31, 2025?

A. As evidenced by Schedule F4 of Exhibit A-11 (NEB-11), an SL-6 customer with one 100-Watt LED fixture, one pole, and one span of conductor will receive a monthly bill of $6.79. This constitutes a decrease of $0.48, or -6.54%.

Q. Are the proposed rates for the 12-month period ending on December 31, 2025, in this proceeding designed to collect the required revenues indicated by the Company's COSS, inclusive of the operating income adjustments included on Exhibit A-6, Schedule A1 (EWS-1), to the extent practical?

A. Yes.

Distributed Generation Program

Q. Please describe the required changes to the Company's existing distributed generation program.

A. Section 173 of PA 295 of 2008, as amended; MCL 460.1173, section (3) dictates:

> *An electric utility or alternative electric supplier is not required to allow for a distributed generation program that is greater than 10% of its average in-state peak load for the preceding 5 calendar years.*

UPPCO understands this new provision of law to require an increase to the distributed generation program size cap over the program size prescribed by the statutory provision superseded by current law.

Q. What is the current cap on the Company's distributed generation program size?

A. Per the Commission's March 24, 2023 order approving settlement in Case No. U-21286, UPPCO's current distributed generation cap is 4.5%.

Q. What is UPPCO's proposal relating to the distributed generation cap for the purposes of this proceeding?

A. UPPCO intends to increase its distributed generation program cap from 4.5% to 10%, consistent with MCL 460.1173(3). A redline tariff sheet reflecting this adjustment is included with Exhibit A-11, Schedule F5 (NEB-12).

Residential Income Assistance Program

Q. Please describe the authorized participation in the Company's Residential Income Assistance ("RIA") program.

A. Please refer to the Commission's March 24, 2023 order approving settlement in Case No. U-21286. Specifically, paragraph 9 (j)(3) describes that the costs for the program, to be included in the calculation of rates, based upon an assumed RIA participation of 1,500 per month.

Q. Please describe the actual participation in the RIA program since it was implemented in July 2023.

A. Table 1 below outlines the actual monthly participation in the Company's RIA program.

	RIA Participation	
	Credits	Amount
Jul-23	1339	$ 20,085
Aug-23	1347	$ 20,205
Sep-23	1324	$ 19,860
Oct-23	1348	$ 20,220
Nov-23	1085	$ 16,275
Dec-23	1383	$ 20,745
Jan-24	1436	$ 21,540
Feb-24	1215	$ 18,225
Average	1310	$ 19,644

The Company notes that an assumed participation level of 1,500 has been consistent with the actual participation experienced since implementing this tariff provision.

Q. Is the Company proposing an adjustment to the assumed RIA participation rate for the purpose of ratemaking in this proceeding?

A. No.

Q. Does this complete your direct testimony in this proceeding?

A. Yes, it does.

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

ENTRY OF APPEARANCE IN AN ADMINISTRATIVE HEARING

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General Instructions:

Type or print legibly in ink. For assistance or clarification, please contact the Public Service Commission at 517-284-8090.

Please Note: *The Commission will provide* ***electronic*** *service of documents to all parties in this proceeding.*

THIS APPEARANCE TO BE ENTERED IN ASSOCIATION WITH THE ADMINISTRATIVE HEARING:

Case / Company Name: Upper Peninsula Power Company (UPPCO) Docket No. U- 21555

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Upper Peninsula Power Company (UPPCO)
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Sherri A. Wellman

Address Miller Canfield

One Michigan Avenue, Suite 900

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Zip 48933 Phone 517-483-4954

Email wellmans@millercanfield.com

Date 03/21/2024

Signature: Sherri A. Wellman Digitally signed by: Sherri A. Wellman DN: CN = Sherri A. Wellman email = wellmans@millercanfield.com C = AD O = Miller Canfield Date: 2024.03.21 14:41:35 -04'00'

○ I am not an attorney

◉ I am an attorney whose:

Michigan Bar # is P- 38989

____________ Bar # is: ____________
(state)

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PUBLIC SERVICE COMMISSION

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Case / Company Name: Upper Peninsula Power Company (UPPCO) Docket No. U- 21555

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Upper Peninsula Power Company (UPPCO)
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

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Date 03/21/2024

Signature: Paul Collins Digitally signed by: Paul Collins DN: CN = Paul Collins email = collinsp@millercanfield.com C = AD O = Miller Canfield Date: 2024.03.21 14:41:15 -04'00'

- ○ I am not an attorney
- ◉ I am an attorney whose:

Michigan Bar # is P- 69719

________ Bar # is: ________
(state)

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PUBLIC SERVICE COMMISSION

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Type or print legibly in ink. For assistance or clarification, please contact the Public Service Commission at 517-284-8090.

Please Note: *The Commission will provide* ***electronic*** *service of documents to all parties in this proceeding.*

THIS APPEARANCE TO BE ENTERED IN ASSOCIATION WITH THE ADMINISTRATIVE HEARING:

Case / Company Name: Upper Peninsula Power Company (UPPCO) Docket No. U- 21555

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Upper Peninsula Power Company (UPPCO)
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Benjamin J. Holwerda

Address Miller Canfield

One Michigan Avenue, Suite 900

City Lansing State MI

Zip 48933 Phone 517-483-4949

Email holwerda@millercanfield.com

Date 03/21/2024

Signature: Benjamin J. Holwerda

Digitally signed by: Benjamin J. Holwerda
DN: CN = Benjamin J. Holwerda email = holwerda@millercanfield.com C = US O = Miller Canfield OU = Attorney at Law
Date: 2024.03.21 14:41:01 -04'00'

○ I am not an attorney

◉ I am an attorney whose:

Michigan Bar # is P-82110

______ Bar # is: ______
(state)

EAHR1 - 09/29/2016

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
UPPER PENINSULA POWER COMPANY	)	Case No. U-21555
for authority to increase its rates for	)	
the generation and distribution of	)	
electricity and for other relief.	)	

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF INGHAM)

Victoria J. Seyfried, being first duly sworn, deposes and states that on March 21, 2024, she served a copy of the following, together with this Proof of Service upon the parties set forth on the attached Service List via electronic mail:

1. Application of Upper Peninsula Power Company for authority to increase its rates for the generation and distribution of electricity and other relief;
2. Certification of Filing Requirements;
3. Direct Testimonies and Exhibits Natasha L. Wonch, Nicholas E. Kates, John S. Thompson, Jay R. Ringler, Virgil E. Schlorke, Daniel J. Gervae, Jason J. Brynick, Kay L. Ryan, Nicole E. Bell, and Eric . Stocking;
4. Documentation that complies with Part II and Part III of the Rate Case Filing Requirements;
5. Proposed Protective Order; and
6. Appearances of Sherri A. Wellman, Paul M. Collins, and Benjamin J. Holwerda;

Victoria J. Seyfried

Digitally signed by: Victoria J. Seyfried
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Date: 2024.03.21 14:38:33 -04'00'

Victoria J. Seyfried

Subscribed and sworn to before me
on this 21st day of March, 2024.

Kacey O'Neill

Digitally signed by: Kacey O'Neill
DN: CN = Kacey O'Neill email = oneill@millercanfield.com C = AD
Date: 2024.03.21 14:38:12 -04'00'

Kacey O'Neill, Notary Public
State of Michigan, County of Livingston
My Commission Expires: 12/26/26
Acting in the County of Ingham

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
UPPER PENINSULA POWER COMPANY	)	Case No. U-21555
for authority to increase its rates for	)	
the generation and distribution of	)	
electricity and for other relief.	)	

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