Founded in 1852
by Sidney Davy Miller

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September 8, 2022

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

Re: Upper Peninsula Power Company
Case No.: U-21286

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. Direct Testimonies and Exhibits of Gradon R. Haehnel, Natasha L. Wonch, Stephen S. Lillie, Jay R. Ringler, Adrian M. McKenzie, Kay L. Ryan, Eric W. Stocking and Nicole E. Bell;
6. Documentation that complies with Part II of the Rate Case Filing Requirements;
7. Appearances of Sherri A. Wellman and Paul M. Collins; and
8. Proof of Service upon the parties from Case Nos. U-17895 and U-20276.

Sincerely,

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

Paul M. Collins
Digitally signed by: Paul M. Collins
DN: CN = Paul M. Collins email = collinsp@millercanfield.com C = US O = Miller Canfield
Date: 2022.09.08 14:41:08 -04'00'

By: ______________________
Paul Michael Collins

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Enclosure

cc: Gradon R. Haehnel
Eric W. Stocking

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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-21286

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 July 31, 2017.

5. UPPCO's present electric rates are based on the schedule of rates authorized by the Commission in its Order Approving Settlement Agreement dated May 23, 2019, in Case No. U-20276. That Order Approving Settlement Agreement granted rate relief of $1.8 million annually, based on a 9.9% return on common equity, effective for the billing month of June 2019, and continued the imposition of certain revenue offsets first authorized in Case No. U-17895 for a finite period that has since expired. The Commission-approved rates were based on a 2019 test year.

6. UPPCO's rates for retail electric service established in Case No. U-20276 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 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 June 30, 2024. Using a July 2023 to June 2024 test year and a return on common equity of 10.8%, UPPCO calculates a base rate revenue deficiency of approximately $25.3 million. As mentioned *supra*, UPPCO's current rates reflect revenue offsets that were first established by the Commission in Case No. U-17895 and continued in Case Nos. U-20150 and U-20995. These revenue offsets expired in June 2022. Properly accounting for the expiration of these regulatory offsets contributes approximately $8 million to the Company's revenue deficiency. When excluding the effects of the expired revenue offsets on UPPCO's existing rates, UPPCO is seeking jurisdictional rate relief of approximately $17.3 million annually. 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. In addition to reflecting and accounting for the expiration of the revenue offsets discussed above, the key drivers contributing to the Company's revenue deficiency are:

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

(b) rising operational costs 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 $25.3 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 various revisions to its electric tariffs, including a new Residential Low-Income tariff and a new Residential and Small Commercial electric heat program. 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 July 8, 2023, 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 10.8%;

D. Authorize UPPCO to file and make effective, at the earliest possible date, but no earlier than July 8, 2023, 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 M. Collins

Digitally signed by: Paul M. Collins
DN: CN = Paul M. Collins email = collinsp@millercanfield.com C = US O = Miller Canfield
Date: 2022.09.08 14:41:28 -04'00'

Dated: September 8, 2022 By:____________________________________

One of Its Attorneys
Sherri A. Wellman (P38989)
Paul M. Collins (P69719)
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-21286

- 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.

- A pre-hearing will be held:

DATE/TIME:	**__, ___, 2022 at __ AM**
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 mpscedockets@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) September 8, 2022 application for approval to increase its existing rates and charges for retail electric service. UPPCO requests Commission approval to: 1) remove the effects of revenue offsets, first established in Case No. U-17895, which have since expired, and provide additional revenue in the amount of $25,280,285 annually; 2) adjust its existing retail electric service rates so as to produce a return on common equity of not less than 10.8%; and 3) file and make effective no earlier than July 8, 2023, its proposed increases to annual revenue, and approve other modifications to the rates, rules, and regulations. The primary drivers for this rate case are the expiration of the revenue offsets first established in Case No. U-17895, increasing costs needed to maintain reliable electric service, and capital investments for needed distribution system reliability and resiliency of improvements. UPPCO proposes to ease the immediate effects of the rate increase by implementing it over a two-year period.

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 _______, 2022. (Interested persons may elect to file using the traditional paper format.) The proof of service shall indicate service upon Upper Peninsula Power Company's attorney, Paul M. Collins, One Michigan Ave., Ste. 900, Lansing, MI 48933.

The prehearing is scheduled to be held remotely by video conference or teleconference. Persons filing a petition to intervene will be advised of the process to participate in the hearing.

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-21286**. 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.

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 300, as amended, MCL 462.2 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 Parts 1 & 4 of the Michigan Office of Administrative Hearings and Rules, Mich. Admin Code, R 792.10106 and R 792.10401 through R 792.10448.

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-21286

PROTECTIVE ORDER

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 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; and

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).

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-21286 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 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-21286." 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-21286. 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. 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 and only remains available to the Receiving Party until the time expires for petitions for rehearing of a final MPSC order in Case No. U-21286 or until the MPSC has ruled on all petitions for rehearing in this case (if any). However, 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 certify in writing to the Disclosing Party that the Protected Material has been destroyed. Counsel for the requesting Party or Parties may maintain in a single confidential file of Protected Material subject to all other provisions in this Order. If the Protected Material is relevant or reasonably calculated to lead to admissible evidence in a future Commission case relating to and involving the Disclosing Party, then it may be used subject to the issuing of a new protective order in that case. 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 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

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-21286

<u>NONDISCLOSURE CERTIFICATE</u>

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-21286, 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: _________, 2022

____
Title:
Representing:

____
Printed Name

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-21286

CERTIFICATION OF FILING REQUIREMENTS

Eric W. Stocking, Manager of Rates & Power Supply for Upper Peninsula Power Company, states that he has provided the data required pursuant to the Rate Case Filing Requirements established by the Commission's order dated July 31, 2017, issued in Case No. U-18238, and pursuant to these requirements, certifies the data so provided.

Eric W. Stocking

Dated: September 8, 2022

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

In the matter of the application of	)	
UPPER PENINSULA POWER COMPANY	)	
for authority to increase retail electric rates for	)	**Case No. U-21286**
the generation and distribution of	)	
electricity and other relief.	)	
	)	

DIRECT TESTIMONY OF

GRADON R. HAEHNEL

FOR

UPPER PENINSULA POWER COMPANY

September 8, 2022

QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Gradon R. Haehnel. 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") and head of Regulatory Affairs for Upper Peninsula Power Company ("UPPCO" or the "Company").

Q. Please summarize your background.

A. My education includes a Bachelor of Science in Finance from Indiana University of Pennsylvania, as well as a Master of Science in Resource and Applied Economics from the University of Alaska at Fairbanks. Since 2005, I have served in various positions of increasing responsibility for two investor-owned electric utilities, including UPPCO. From 2005 through 2016, I worked at Emera Maine, currently Versant Power, an electric transmission and distribution utility serving customers in rural central and northern Maine. While at Emera Maine, I worked in various leadership capacities, including finance, regulatory affairs, and asset management.

Since joining UPPCO in 2016, I have worked in both regulatory affairs and finance, serving previously as Vice President of Regulatory Affairs. Currently I serve as UPPCO's CFO and head of Regulatory Affairs. As CFO and head of Regulatory Affairs, my primary accountabilities include leading the accounting, finance, tax, corporate reporting, financial planning, power supply, regulatory affairs, and energy waste reduction efforts for UPPCO.

Q. Have you previously testified in any regulatory proceedings?

A. Yes. I have testified before both the Maine Public Utilities Commission and the Michigan Public Service Commission ("MPSC" or the "Commission") in various dockets since 2005.

PURPOSE OF TESTIMONY

Q. What is the purpose of your direct 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) overview of forecast methodology, (2) explanation of revenue deficiency, (3) explanation of UPPCO's rate implementation plan, (4) explanation of UPPCO's forecasted adjustments and inputs, (5) 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 (6) information technology capital expenditures.

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:

General Case Overview

Section I: Forecast Methodology

Section II: Revenue Deficiency

Section III: Rate Implementation Plan

Section IV: Forecast Adjustments

Section V: Capital Structure

Section VI: Information Technology CAPEX

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 (GRH-1), Historical Rate of Return Summary
- Exhibit A-4 (GRH-2), Historical Cost of Long-Term Debt
- Exhibit A-4 (GRH-3), Historical Cost of Short-Term Debt
- Exhibit A-4 (GRH-4), Historical Cost of Preferred Stock
- Exhibit A-4 (GRH-5), Historical Cost of Common Shareholders' Equity
- Exhibit A-6 (GRH-6), Projected Revenue Deficiency / Base Case
- Exhibit A-6 (GRH-7), Projected Revenue Deficiency / Rates Year 1
- Exhibit A-6 (GRH-8), Projected Revenue Deficiency / Rates Year 2
- Exhibit A-9 (GRH-9), Projected Rate of Return Summary
- Exhibit A-9 (GRH-10), Projected Cost of Long-Term Debt

- Exhibit A-9 (GRH-11), Projected Cost of Short-Term Debt
- Exhibit A-9 (GRH-12), Projected Cost of Preferred Stock
- Exhibit A-9 (GRH-13), Projected Cost of Common Shareholders' Equity
- Exhibit A-12 (GRH-14), Forecast Adjustments/Inputs Summary
- Exhibit A-13 (GRH-15), Inflation Factor
- Exhibit A-14 (GRH-16), Percent Salary & Wage (S&W) Adjustment - Union
- Exhibit A-15 (GRH-17), Percent Salary & Wage (S&W) Adjustment - Non Union
- Exhibit A-16 (GRH-18), Union S&W Adjustment - Production
- Exhibit A-17 (GRH-19), Union S&W Adjustment - Distribution
- Exhibit A-18 (GRH-20), Union S&W Adjustment - Customer Accounts
- Exhibit A-19 (GRH-21), Non Union S&W Adjustment - Administrative
- Exhibit A-20 (GRH-22), Vegetation Management
- Exhibit A-21 (GRH-23), Energy Waste Reduction (EWR)
- Exhibit A-22 (GRH-24), Bad Debt Expense
- Exhibit A-23 (GRH-25), Depreciation & Amortization Expense
- Exhibit A-24 (GRH-26), Executive Deferred Compensation Expense
- Exhibit A-25 (GRH-27), Pension & OPEB Expense
- Exhibit A-45 (GRH-28), AFUDC Calculation
- Exhibit A-46 (GRH-29), Willis Towers Watson Report
- Exhibit A-47 (GRH-30), U-20757 Deferred Uncollectible
- Exhibit A-48 (GRH-31), Revolver Calculation
- Exhibit A-49 (GRH-32), Free Cash Flow
- Exhibit A-50 (GRH-33), WTW Welfare Expense Report

- Exhibit A-51 (GRH-34), WTW Pension Expense Report
- Exhibit A-52 (GRH-35), Information Technology Projects for 2023-2024

I am also referencing the following exhibits that are sponsored by Company Witness Stephen S. Lillie.

- Schedule B5 of Exhibit A-7 (SSL-1)
- Schedule B5.1 of Exhibit A-7 (SSL-2)
- Schedule B5.4 of Exhibit A-7 (SSL-3)
- Schedule B5.5 of Exhibit A-7 (SSL-4)
- Schedule B5.6 of Exhibit A-7 (SSL-5)

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 filing:

- **Natasha L. Wonch** presents testimony in support of the Company's proposed revenue requirement calculations, including revenue, operating expenses, taxes, and calculation of rate base.

- **Adrien McKenzie** presents testimony in support of the Company's requested Return on Equity and common equity ratio.

- **Stephen S. Lillie** presents testimony in support of the Company's proposed capital expenditures for Distribution, Generation, Substation, and General and Common. Mr. Lillie also addresses the Company's vegetation management program.

- **Jay R. Ringler** presents testimony in support of the Company's proposed Distribution Reliability projects, including strategic underground conversion of overhead conductors, and UPPCO's distribution reliability metrics.

- **Kay L. Ryan** presents testimony in support of the Company's employee benefits and other Human Resources related matters.

- **Eric W. Stocking** presents testimony in support of the Company's proposed Cost of Service Study ("COSS"), compliance with prior Commission directives, Power Supply Cost considerations, State Reliability Mechanism calculations, Residential class low-income tariff offering and electric heat pump rebate program.

- **Nicole E. Bell** presents testimony in support of the projected test year sales forecast, proposed rate design, and 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, 2021.

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

A. UPPCO has used a projected test year ending June 30, 2024.

Q. How does the Company present the historical and projected 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 15 counties. Founded in 1947 with roots dating much earlier, the Company has a predominantly rural service area that spans over 4,460 square miles with company-owned generation capacity of approximately 57 MW, including 7 hydro-electric facilities.

Q. Assuming a projected test year beginning on July 1, 2023, how many times will UPPCO's distribution revenue requirement have changed since January 1, 2017?

A. <u>One time</u>, over this 6 ½ year period.

Q. By what percentage did UPPCO's distribution revenue requirement change in that one instance referenced above?

A. Excluding impacts from the federal Tax Cut and Jobs Act of 2017 ("TCJA"), UPPCO's distribution revenue requirement changed by <u>only 1.8%</u>.

Q. What jurisdictional rate relief did the Commission approve in UPPCO's most recent and previous electric general rate proceeding?

A. UPPCO's most recent general rate case was decided in 2019. In MPSC Case No. U-20276, the Commission authorized an annual revenue increase of $1,800,000 or approximately 1.8% excluding impacts from the TCJA, on May 23, 2019. In that case, the Commission issued a final order approving settlement, which among other things, continued the imposition of certain revenue offsets reflected in based rates that were first authorized in Case No. U-17895 for a finite period that have since expired.

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

A. As an initial matter, the Company must file a general rate case in order to properly account for the revenue offsets that have since expired. Furthermore, as previously stated, over the last 6 ½ years the Company has increased distribution rates by only 1.8% annually, thereby evidencing that UPPCO is effectively managing costs over this period for the direct benefit of our customers. However, given the current inflationary economic environment putting upward pressure on prices, and in conjunction with UPPCO's continued investment in infrastructure and operations, the Company has initiated this rate proceeding so it can continue to improve and effectively manage deployment of both capital and operating resources needed to ensure safe, reliable, and efficient delivery of electricity and service to our customers.

Additionally, in Case No. U-20995, UPPCO agreed to a rate case stay-out provision of no less than 18 months. In accordance with the settlement agreement in Case No. U-20995 and pursuant to the filing of this instant case, over 24 months will have passed since the June 3, 2021 acquisition date.

Q. Please summarize the key drivers of the Company's request in this case.

A. The Company requests jurisdictional rate relief in the amount of $17.3 million, which is summarized as shown in Table 1:

Table 1 (in millions)

Key Drivers of Revenue Requirement	**Total**	**% Annual Change Since Last Case***
Investment	$ 7.9	
Cost of Capital	$ 0.0	
Operating Expenses (excluding O&M)	$ 5.3	1.5%
O&M Expenses	$ 4.2	1.8%
Sales / Revenue	$ (0.1)	
Jurisdictional Rate Relief	$ 17.3	
Accounting for Expired Revenue Credits	$ 8.0	
Total Revenue Requirement Impact	$ 25.3	

** compound annual growth rate*

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

A. Table 1 is a financial bridge from UPPCO's most recent electric rate case outcome, Case No. U-20276, to the Company's requested jurisdictional rate relief, excluding revenue offset impacts, based on a projected test year ending June 30, 2024.

Based on the evidentiary support provided in this filing, 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 $25.3 million annually based on a projected 12-month test year ending June 30, 2024. Approximately $8.0 million of the annual increase in revenue requirement accounts for and/or is related to the expiration of the revenue offsets first-established in Case No. U-17895.

The remaining "jurisdictional rate relief" portion of the increase in revenue requirement totaling $17.3 million is primarily driven by UPPCO's continued infrastructure investments and associated operating expenditures needed to improve the reliability and resiliency of UPPCO's distribution system.

Q. Please explain how UPPCO is managing its operating expenditures from its most recent rate case proceeding (U-20276) through the projected test year ending June 30, 2024.

A. As evidenced in Table 1 above, operating expenditures, excluding O&M and holding power supply changes constant to the historical test year ending December 31, 2021, are anticipated to increase at a compound annual growth rate of 1.5%. Also, as evidenced in Table 1, operations and maintenance ("O&M") expenses are anticipated to increase at a compound annual growth rate of 1.8%. When compared to the Congressional Budget

Office's ("CBO") May 2022[1] report titled, *The Budget and Economic Outlook: 2022 to 2032*, which lists actual and projected inflation rates over that same time period, both of UPPCO's compound annual growth rates are well below the 3.51% compound annual growth rate supported by this CBO report. To calculate this rate, UPPCO took an average of actual Consumer Price Index ("CPI") rates for 2020 and 2021 and forecasted CPI rates for 2022 through 2024 as published in the CBO report for May 2022. I support this calculation in further detail later in my testimony when explaining UPPCO's forecast adjustments to the projected test year. Based on a comparison to the inflation benchmark, it is clear that UPPCO is managing its total operating expenses both effectively and efficiently for the benefit of our customers.

Q. How is UPPCO looking to implement rates?

A. UPPCO is proposing to ease the immediate impacts of the proposed jurisdictional rate relief by phasing in the requested adjustment over a two-year period beginning with the initial rate adjustment occurring on July 1, 2023, and the final and full rate adjustment occurring on July 1, 2024. For the initial rate adjustment to occur on July 1, 2023, the Company's will adjust rates to recover only 50% of its full revenue deficiency. UPPCO will then establish a regulatory asset for the remaining 50% of its full first year revenue deficiency (i.e., deferred revenue) to be recovered over a forward looking 3-year period beginning on July 1, 2024. Per the Company's proposed rate implementation plan, the revenue adjustment to operating revenues will be approximately 11.68% in first year,

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

followed by 13.94% in the second year. Later in my testimony, I provide a more detailed explanation of UPPCO's rate implementation plan.

SECTION I: FORECAST METHODOLOGY

Q. What general approach did the Company use in supporting its projected test year positions and recommendations in this case?

A. UPPCO has used actual historical data as the point of departure for most estimated cost levels for the projected test year. These historical costs were then adjusted for the impact of inflation. Certain other costs reflect specific estimates or projections where general impacts of inflation would alone not be appropriate. Costs not adjusted solely by the inflation factor are addressed specifically in testimony or evidenced in the Company's forecasted adjustment / inputs.

Q. Please describe the major components of UPPCO's forecast that informed the projected test year ending June 30, 2024.

A. The major components are as follows:

1. <u>Sales and demand forecast</u>. 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 annual sales projections is evidenced in Schedule E1 of Exhibit A-5 (NEB-1).

2. Power supply. For purposes of establishing jurisdictional revenue requirements, UPPCO has utilized a power supply forecast that reflects costs equivalent to its 2021 historical test year costs. The PSCR factor and assumptions used to calculate present revenues with present rates in this general rate case proceeding are further explained by Company Witness Stocking in his direct testimony. More specifically, 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, UPPCO applies the appropriate retail and wholesale rates to derive its revenue forecasts. 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.

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 operation and maintenance forecasts are production, distribution, customer accounts, customer service and administrative and general expenses. For these costs, UPPCO used the 2021 historical test year costs as the basis for the projected test year. Then, UPPCO escalated these 2021 historical test year costs by an inflation factor to derive the projected test year values, and then made certain forecast adjustments/inputs to the projected test year based on other budgetary and/or known information. A summary of these forecast adjustments is identified in Exhibit A-12 (GRH-14), Forecast Adjustments/Inputs Summary. A summary of operating expenses is evidenced at line 10 of Schedule C1 of Exhibit A-8 (NLW-23).

5. Capital expenditures forecast. The capital expenditure forecast is developed by finance, along with UPPCO's engineering and planning groups 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 capital expenditure forecast for the distribution, substation, generation, fleet, and facilities investments is provided by Company Witness Lillie and Company Witness Ringler. More specifically, a summary of the capital expenditures for the projected test year are evidenced in Exhibit A-26 (SSL-6), UPPCO Capital Expenditures (CAPEX) by Business Line. Both witness Lillie and witness Ringler describe capital projects planned over two calendar years because the projected year spans two fiscal/calendar years and UPPCO desires scheduling flexibility to be able to move one or more projects between fiscal years, while maintaining the targeted capital spending for the projected test year.

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 requirements, availability of equity capital, and corporate objective such as credit metrics, large capital projects and short-term debt limitations. Later in my direct testimony, I support UPPCO's proposed capital structure through the end of the projected test year. More specifically, a summary of the Company's proposed capital structure is evidenced in Schedule D1 of Exhibit A-9 (GRH-9).

SECTION II: PROJECTED TEST YEAR REVENUE DEFICIENCY

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

A. Schedule A1 of Exhibit A-6 (GRH-6) calculates UPPCO's projected test year revenue deficiency for the year ending June 30, 2024 based on 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 the expiration of revenue offsets first established in Case No. U-17895 and continued in Case No. U-20276 is then applied to the revenue requirement, which increases the revenue deficiency. The final revenue deficiency is then added to presently forecasted revenues for the Company to achieve its required rate of return.

At line 30 of Schedule A1 of Exhibit A-6 (GRH-6), the UPPCO's total revenue deficiency is $25,616,059 and UPPCO's retail revenue deficiency is $25,280,285 for the projected test rear. These revenue deficiencies, represent a percentage increase of both 23.49% and 23.35%, to present revenues, respectively.

Q. Please describe the revenue offset and adjustments listed beginning on line 18 through 22 of Schedule A1, Schedule A1.1, and Schedule A1.2 of Exhibit A-6.

A. UPPCO proposes the following revenue offset and adjustments:

- U-20995 Revenue Offset: 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 recognized by settlement point 2.h., whereby the

Commission directed the following: (1) extended the expiration of certain "revenue credits"[2] 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. At line 18 of Schedule A1 of Exhibit A-6 (GRH-6), the revenue offset is valued at $2,537,673 which reflects a 12-month period of the two-year amortization period including the application of carrying costs equivalent to the Company's weighted average cost of capital. This revenue adjustment expires on June 30, 2025.

- 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 telecommunication 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 (the date of Governor Whitmer's Executive Order 2020-21) that are in excess of

[2] These certain "revenue credits", which are called revenue offsets elsewhere in this testimony, are evidenced in the 2021 historical test year revenue requirement model at lines 18 and 20 of Schedule A1 of Exhibit A-1 (NLW-1) sponsored by Company Witness Wonch.

the amount used to set current rates."[3] Further, consistent with UPPCO's response to the July 7 Order issued by the Commission on July 7, 2022 in this same case, UPPCO described its accounting treatment and cost recovery with respect to the deferred uncollectible expenses the Company has recorded. As evidenced in Exhibit A-47 (GRH-30), U-20757 Deferred Uncollectible, to date, UPPCO has deferred $863,118 of uncollectible expense to the U-20757 deferred asset account authorized by the April 15 Order. Also, in Case No. U-20995, settlement point 2.l., of the approved settlement agreement states:

> *"As part of Axium UP's commitment to integrating Environmental, Social, and Corporate Governance matters into its management strategy, in its next rate case under its new ownership, UPPCO will forgive 20% of the bad debt booked to the Company's Covid 19 deferred asset account, which shall be borne by shareholders and shall not be recovered from ratepayers. UPPCO will propose an arrears forgiveness program, in consultation with the Staff and the Attorney General, within 90 days form settlement execution, to provide the benefit of the bad debt expense forgiven above to customer arrearages."*

Therefore, upon Commission approval in this case, UPPCO plans to retire 20% of the deferred $863,118 and discontinue the accrual in September 2022. At line 20 of Schedule A1 of Exhibit A-6 (GRH-6), UPPCO proposes a two-year amortization period reflecting the value of $431,559, excluding the 20% write-off note above, for full recovery of this regulatory asset that will be expiring on June 30, 2025. Again, upon Commission order, UPPCO will write-off a 20% of this regulatory asset valued at $172,624.

[3] See April 15 order, p. 15; see also, id., pp. 21, 22.

- U-20276 Revenue Adjustment: As established in Case No. U-20276, settlement point 9.i. directs 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 date as approved by the Commission in a future rate proceeding. As such, at line 22 of Schedule A1 of Exhibit A-6 (GRH-6), the Company calculates a value of ($412,379) which represents a 12-month period of the full regulatory liability being amortized over a three-year period.
- U-21286 Revenue Adjustment: At line 24 in Schedule A1.2 of Exhibit A-6 (GRH-8), UPPCO proposes a retail revenue offset equivalent to $4,213,381. As described in more detail later in my testimony as part of our rate implementation plan, this value represents 50% of the first-year retail revenue deferral of $12,640,343, as evidenced at line 22 in Schedule A1.1 of Exhibit A-6 (GRH-7). The previously mentioned $4,213,381 value is simply the $12,640,143 proposed regulatory asset value divided by the proposed three-year amortization period. This regulatory asset will accrue a carrying charge equivalent to the Company's weighted average cost of capital.

SECTION III: RATE IMPLEMENTATION PLAN

Q. Please describe the Company's proposed rate implementation plan to fully recover the revenue deficiency amount evidenced on Schedule A1 of Exhibit A-6 (GRH-6).

A. UPPCO is proposing to ease the immediate impact of the proposed rates by phasing in rates over a two-year period beginning with the initial rate adjustment occurring on July 1, 2023, and the final rate adjustment occurring on July 1, 2024. For the initial rate adjustment to occur on July 1, 2023 through June 30, 2024, the Company will implement rates to recover 50% of its full revenue deficiency. As part of this phasing in, UPPCO will establish a regulatory asset for the remaining 50% of its full first year revenue deficiency (i.e., deferred revenue) to be amortized and recovered over a forward looking 3-year period beginning on July 1, 2024. For the final rate adjustment to occur on July 1, 2024, the Company will adjust rates to recover its full revenue deficiency, plus the one-third of its deferred revenue from year one. The regulatory asset established to fully recover the deferred revenue from year one, will accrue at the Company's after-tax WACC and be amortized over a three-year period beginning July 1, 2024, and ending June 30, 2027.

Q. Please explain how this rate implementation plan benefits customers.

A. By phasing in the implementation of the new rates over a two-year period, UPPCO can ease the year one rate impacts for customers thereby creating a smoother glidepath to final rates that ensure full recovery of UPPCO's revenue deficiency. It has been over four years since the Company has last adjusted distribution rates. The Company views this phase-in as certainly reasonable.

Q. Please describe how the Company is presenting its rate implementation plan.

A. As noted above, Schedule A1 of Exhibit A-6 (GRH-6) represents UPPCO's full revenue deficiency without UPPCO's recommended rate implementation plan. Schedule A1.1 of Exhibit A-6 (GRH-7) presents year one of UPPCO's rate implementation to occur on July 1, 2023. Schedule A1.2 of Exhibit A-6 (GRH-8) presents year two of UPPCO's rate implementation to occur on July 1, 2024.

Q. Please describe the revenue deficiency as calculated on Schedule A1.1 of Exhibit A-6 (GRH-7) for year *<u>one</u>* rate implementation.

A. Commencing year one, UPPCO proposes to phase in the new rates by implementing rates that will collect only 50% of the full revenue deficiency throughout the first year. As evidenced at Line 22 of Schedule A1.1 of Exhibit A-6 (GRH-7), the total deferred revenue value resulting from this phase in is ($12,808,029), and the deferred retail revenue value is ($12,640,143). These values are calculated by simply multiplying the full revenue deficiency amount evidenced at Line 22 of Schedule A1 of Exhibit A-6 (GRH-6) by 50%. As can be seen at Line 30 of Schedule A1.1 of Exhibit A-6 (GRH-7), the resulting deficiencies for total and retail revenues are $12,808,029 and $12,640,143, respectively. For retail revenues, the phased in year one revenue deficiency is now 11.68% of present revenues as evidenced at Line 34. The remaining portion of the year one revenue deficiency will be recorded as a regulatory asset to be amortized and collected over a three-year period beginning in July 2024.

Q. Please describe the revenue deficiency as calculated on Schedule A1.2 of Exhibit A-6 (GRH-8) for year *<u>two</u>* rate implementation.

A. Commencing year two, UPPCO will complete the phasing in of the new rates by implementing rates that will collect the full revenue deficiency, plus the first year of the three-year amortization of the deferred revenue regulatory asset. As evidenced at Line 22 of Schedule A1.2 of Exhibit A-6 (GRH-8), this amortization of the year one regulatory asset results in a total revenue value addition of $4,269,243, and a retail revenue value addition of $4,213,381. These values are calculated by simply dividing the first year's deferred revenue values from Line 22 of Schedule A1.1 of Exhibit A-6 (GRH-7) by three.

To calculate the year 2 revenue deficiency represented at Line 30 of Schedule A1.2 of Exhibit A-6 (GRH-8), the Company simply subtracted the year 1 revenue deficiency from Line 30 of Schedule A1.1 of Exhibit A-6 (GRH-7) from the year 2 revenue deficiency at line 24 of Schedule A1.2 of Exhibit A-6 (GRH-8). For retail revenues, the year two revenue deficiency is only 13.94% of present revenues as evidenced at Line 34.

SECTION IV: PROJECTED TEST YEAR FORECAST ADJUSTMENTS/INPUTS

Q. Please describe how the Company's projected test year revenue requirement ending June 30, 2024, is developed?

A. UPPCO's methodology utilized a historical 2021 test year. UPPCO then escalated the historical 2021 costs by inflation to derive projected test year values. To achieve these modeled results, UPPCO applied an inflation factor to costs for the years 2022, 2023 and 2024 and then typically averaged the 2023 and 2024 values to calculate the value representing the July 1, 2023, through June 30, 2024, projected test year.

Q. How does UPPCO present its forecast adjustments/inputs for the projected test year ending June 30, 2024?

A. Please find Exhibit A-12 (GRH-14), Forecast Adjustments/Inputs Summary.

Q. Please explain Forecast Adjustment 1 as evidenced in Exhibit A-12 (GRH-15), Inflation Factor.

A. UPPCO applied an annual inflation factor of 3.51% to derive its projected test year costs. To calculate this rate, UPPCO took an average of actual CPI rates for 2020 and 2021 and forecasted CPI rates for 2022 through 2024 as published in the CBO report for May 2022[4], 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 CBO's forecast for the Consumer Price Index which is a reasonable proxy for inflation.

Q. Please explain Forecast Adjustment 2 as evidenced in Exhibit A-13 (GRH-15), Percent Salary & Wage (S&W) Adjustment - Union

A. UPPCO applied a wage and salary adjustment of ______________________ for its union workforce. To calculate this rate, UPPCO utilized data in the same CBO report published in May 2022 that informed the Company's annual inflation factor. By utilizing actual Wage and Salary income data for 2020 and 2021 and forecasted Wage and Salary data for 2022 through 2024, the Company calculated an average ____________________ forecast to be applied. 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-15 (GRH-17), Percent Salary & Wage (S&W) Adjustment - Non Union.

A. As evidenced in Forecast Adjustment 2, UPPCO applied the same _____ _______________ wage and salary adjustment for its non-union, administrative employees.

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

Q. Please explain Forecast Adjustment 4 as evidenced in Exhibit A-16 (GRH-18), Union S&W Adjustment – Production.

A. UPPCO has calculated the incremental salary and wage adjustment for the production (FERC 544) operational area to be $36,030 for the projected test year as evidenced at line 33 of Exhibit A-16 (GRH-18), Union S&W Adjustment - Production. In order to calculate this value, UPPCO escalated 2021 historical test year total union wages by the forecast adjustments noted in Forecast Adjustment 1. UPPCO then allocated these costs amongst the three general operational categories where these costs exist: Production (FERC 544), Distribution (FERC 582) and Customer Accounts (FERC 903).

Q. Please explain Forecast Adjustment 5 as evidenced in Exhibit A-17 (GRH-19), Union S&W Adjustment – Distribution.

A. UPPCO has calculated the incremental salary and wage adjustment for the distribution (FERC 582) operational area to be $83,214 for the projected test year as evidenced at line 34 of Exhibit A-17 (GRH-19), Union S&W Adjustment - Distribution. In order to calculate this value, UPPCO escalated 2021 historical test year total union wages by the forecast adjustments noted in Forecast Adjustment 1. UPPCO then allocated these costs amongst the three general operational categories where these costs exist: Production (FERC 544), Distribution (FERC 582) and Customer Accounts (FERC 903).

Q. Please explain Forecast Adjustment 6 as evidenced in Exhibit A-18 (GRH-20), Union S&W Adjustment - Customer Accounts.

A. UPPCO has calculated the incremental salary and wage adjustment for the customer accounts (FERC 903) operational area to be $16,480 for the projected test year as evidenced at line 35 of Exhibit A-18 (GRH-20), Union S&W Adjustment - Customer Accounts. In order to calculate this value, UPPCO escalated 2021 historical test year total union wages by the forecast adjustments noted in Forecast Adjustment 1. UPPCO then allocated these costs amongst the three general operational categories where these costs exist: Production (FERC 544), Distribution (FERC 582) and Customer Accounts (FERC 903).

Q. Please explain Forecast Adjustment 7 as evidenced in Exhibit A-19 (GRH-21), Non Union S&W Adjustment – Administrative.

A. UPPCO has calculated the incremental salary and wage adjustment for the administrative, non-union staff (FERC 920) operational area to be $140,269 for the projected test year as evidenced at line 49 of Exhibit A-19 (GRH-21), Non Union S&W Adjustment - Administrative. In order to calculate this value, UPPCO escalated 2021 historical test year nonunion wages by the forecast adjustments noted in Forecast Adjustment 2.

Q. Please explain Forecast Adjustment 8 as evidenced in Exhibit A-20 (GRH-22), Vegetation Management.

A. As supported the direct testimony and exhibits of Company Witness Lillie, UPPCO operates on a six-year distribution line clearance program and evidences these expenditures on Exhibit A-38 (SSL-11), 6 Year Distribution Line Clearance Program. Since vegetation management and/or line clearance costs are recorded in FERC 593, in Exhibit A-20 (GRH-22), the Company adjusts these figures by the inflation factor of 3.51%. As such, the Company makes a forecast adjustment to the projected test year ending June 30, 2024 by a positive $73,831 to FERC 593 over the 2023 forecasted value.

Q. Please explain Forecast Adjustment 9 as evidenced in Exhibit A-21 (GRH-23), Energy Waste Reduction (EWR).

A. EWR costs are accounted for in FERC 908. UPPCO's 2021 actual EWR costs were $2,985,094. UPPCO's 2022 budget for EWR is $3,386,375 consistent with its 2022 and 2023 EWR plan filing in Case No. U-20879, specifically Exhibit A-2 (AHM-2). UPPCO's forecasted value for the projected test year ending June 30, 2024, is $3,456,955 which represents a growth rate higher than the applied inflation factor of 3.51%. As such, the Company adjusted FERC 908 for the projected test year by $50,834 over the 2023 forecasted value.

Q. Please explain Forecast Input 10 as evidenced in Exhibit A-22 (GRH-24), 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 June 30, 2024, UPPCO utilized a five-year trend value of actual, historical and projected values. Actual data was utilized from 2018 through 2021, plus the 2022 budgeted value and all values were averaged resulting an in an inflation-adjusted value of $434,645 for 2023. In order to calculate the 2024 inflation-adjusted value of $434,645, UPPCO average 2019 through 2021 actuals, plus the 2022 budgeted and 2023 projected value. For the projected test year ending June 30 2024, UPPCO took the simple average of 2023 and 2024 calendar year forecasts to derive a value of $426,310.

Q. Please explain Forecast Input 11 as evidenced in Exhibit A-23 (GRH-25), Depreciation & Amortization Expense.

A. As further supported by Company Witness Wonch and represented in Schedule C6 of Exhibit A-8 (NLW-28), depreciation expense for the projected test year ending June 30, 2024 is $11,500,073, while amortization expense is $3,161,252.

Q. Please explain Forecast Input 12 as evidenced in Exhibit A-24 (GRH-26), Executive Deferred Compensation Expense.

A. As further evidenced by Company Witness Ryan, the Company has an executive deferred compensation program. This expense is recorded in FERC 926.260. For the projected test year ending June 30, 2024, UPPCO forecasts a value of ______. _________________

Q. Please explain Forecast Input 13 as evidenced in Exhibit A-25 (GRH-27), Pension & OPEB Expense.

A. Pensions are a type of employer-sponsored retirement plan. For the projected test year ending June 30, 2024, pension expenses are evidenced at line 6 of Exhibit A-25 (GRH-27), Pension & OPEB 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 June 30, 2024, pension expenses are evidenced at line 12 of Exhibit A-25 (GRH-27), Pension & OPEB Expense. Both pension and OPEB expenses are recorded in FERC 926. Willis Towers Watson US LLC ("WTW") was engaged by UPPCO to provide 2023 and 2024 forecasted benefit cost, based on the 2022 pension and postretirement welfare valuations, for rate case purposes. These valuations were performed in accordance with generally accepted actuarial principles and practices. Exhibit A-46 (GRH-29), Willis Towers Watson Report, provides the 2023 and 2024 budget estimates. This information was prepared in accordance with FASB ASC 715-30 and 715-60.

Assumptions and methods for 2023 and 2024 projects are as follows: (1) discount rates as of December 31, 2022 are based on June 30, 2022 results and are held constant thereafter; (2) actual return on assets for 2022 reflects actual trust returns through June 30, 2022 and 0% return assumed from July 1, 2022 through December 31, 2022. The actual return on assets for 2023 is assumed to be 5.00%; (3) expected rate of return assumption for 2023 and 2024 is 5.00%; (4) contributions assumed in the forecast period for the 2023 and 2024 periods are: (i) Restoration, $31K and $34K, respectively, (ii) SERP, $12K for both periods, (iii) Administrative Medical, $35K and $41K, respectively, and (iv) Retiree Life Insurance, $67K and $117K, respectively with the Retiree Life Insurance Plan assets assumed to be exhausted during 2023; and (4) all other assumptions and methods were selected by UPPCO at year-end 2021 and are summarized in Appendix A of Exhibit A-50 (GRH-33), WTW Welfare Expense Report and Exhibit A-51 (GRH-34), WTW Pension Expense Report regarding the January 1, 2022, accounting valuation reports delivered on June 27, 2022. 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, 2022.

For the projected test year ending June 30, 2022, UPPCO identifies its Other Benefits Expense and escalates them with an inflation factor of 3.51% which are evidenced at line 28 of Exhibit A-25 (GRH-27), Pension & OPEB Expense.

SECTION V: CAPITAL STRUCTURE

Q. Regarding the historical test year ending December 31, 2021, please explain Schedule D1 of Exhibit A-4 (GRH-1).

A. Schedule D1 develops UPPCO's historical test year overall rate of return of 6.96%, 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 44.51% and 55.49%, respectively, as evidenced at lines 2 and 6.

Q. Regarding the historical test year ending December 31, 2021, please explain Schedule D2 of Exhibit A-4 (GRH-2).

A. Schedule D2 develops UPPCO's historical test year cost of long-term debt of 4.69%, based on a 13-month average, as shown at line 23.

Q. Regarding the historical test year ending December 31, 2021, please explain Schedule D3 of Exhibit A-4 (GRH-3).

A. Schedule D3 develops UPPCO's historical test year cost of short-term debt of 4.50%, based on a 13-month average, as calculated at line 27.

Q. Regarding the historical test year ending December 31, 2021, please explain Schedule D4 of Exhibit A-4 (GRH-4).

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

Q. Regarding the historical test year ending December 31, 2021, please explain Schedule D5 of Exhibit A-4 (GRH-5).

A. Schedule D5 develops UPPCO's 13-month average balance of Adjusted Common Equity of $149,985,631 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 June 30, 2024, please explain Schedule D1 of Exhibit A-9 (GRH-9).

A. Schedule D1 develops UPPCO's projected test year overall rate of return of 6.94%, as shown at line 22, based on UPPCO's 13-month average capital structure, and a proposed 10.80% ROE. As a percent of permanent capital, the 13-month proposed debt and equity balances are 46.04% and 53.96%, respectively, as evidenced at lines 2 and 6.

Q. For the projected test year ending June 30, 2024, please explain Schedule D2 of Exhibit A-9 (GRH-10).

A. Schedule D2 develops UPPCO's projected test year cost of long-term debt of 4.27%, based on a 13-month average, as shown at line 23.

Q. For the projected test year ending June 30, 2024, please explain Schedule D3 of Exhibit A-9 (GRH-11).

A. Schedule D3 develops UPPCO's projected test year cost of short-term debt of 6.05%, based on a 13-month average, as calculated at line 27. Please find Exhibit A-48 (GRH-31), Revolver Calculation, whereby UPPCO builds its projection of the 6-month LIBOR rate. As evidenced in Exhibit A-48 (GRH-31), UPPCO utilized historical and forecasted data at https://www.forecasts.org/6mlibor.htm and added the applicable margin rate of 1.625% to project July 2022 through February 2023 revolver rates. From March 2023 through June 2024, UPPCO utilized the forecasted change in LIBOR data from https://longforecast.com/libor-forecast-2017-2018-2019.

Q. For the projected test year ending June 30, 2024, please explain Schedule D4 of Exhibit A-9 (GRH-12).

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

Q. For the projected test year ending June 30, 2024, please explain Schedule D5 of Exhibit A-9 (GRH-13).

A. Schedule D5 develops UPPCO's 13-month average balance of Adjusted Common Equity of $148,963,979 for the projected test year, as shown on line 16 UPPCO requests a 10.8% ROE for the projected test year in this general rate case proceeding, as further supported by Company Witness McKenzie'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 be used. This capital structure represents the actual capital structure as of December 31, 2021, adjusted for the projected changes in debt, equity, and deferred income taxes through the end of the projected test year ending on June 30, 2024. 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 53.96%, while the debt ratio as a percentage of permanent capital is 46.04%. At minimum, this common equity ratio is further supported by the direct testimony and exhibits of Company Witness Adrien McKenzie. In fact, given UPPCO's small utility size, a much higher equity thickness is not unreasonable as pointed out by Company Witness McKenzie.

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 10.80% as evidenced at line 6 of Schedule D1 of Exhibit A-9 (GRH-9). Again, this ROE is supported by Company Witness McKenzie 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 6.94% 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 (GRH-9) 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 exclusively of $127,100,000 of senior secured fixed rate notes with a 3.59% cost rate and a term of 30 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 Canadian Imperial Bank of Canada (CIBC). UPPCO has assumed a 13-month balance of $51,064,396 for the projected test year as evidenced in Schedule D1 of Exhibit A-9 (GRH-9) 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 $148,963,979 for the projected test year as evidenced in Schedule D1 of Exhibit A-9 (GRH-9) at line 6.

Q. Please explain the impact of deferred income taxes on capital structure?

A. Deferred income taxes are a record of book taxes that have been incurred, but not yet paid due to special Internal Revenue Service deductions, measurements, or treatments. This represents a temporary "zero cost" source of funding for the Company and is included as a component of the capital structure at a zero-cost rate which is in compliance with settlement point 9.g. of the final Commission order approving settlement in Case No. U-20276 which states the following:

> *"…The Company will include the entire excess deferred tax regulatory liability within the Company's capital structure as zero cost capital in the next general rate case filing."*

For UPPCO, the assumed 13-month balance of accumulated deferred income taxes is $27,383,181 for the projected test year as evidenced in Schedule D1 of Exhibit A-9 (GRH-9) at line 18.

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, June 30, 2024?

A. No.

Q. Are there any adjustments to the short-term credit facility from the historical test year through the end of the projected test year, June 30, 2024?

A. Yes. UPPCO's projected monthly revolver balance is presented in Exhibit A-49 (GRH-32), 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 describe the debt component of the capital structure at UPPCO *prior* to the sale, as represented in MPSC Case No. U-20995.

A. Prior to the sale, UPPCO had long-term debt of $108.2 million which was an intercompany loan from UPPCO's parent company, UPPHC. At the time of acquisition and since September of 2018, UPPCO's long-term debt rate was 5.46% which included a 100-basis point step-up in the cost imposed by noteholders because UPPCO had a credit rating below investment grade. Also, UPPCO had a $15 million short-term credit facility that was essentially maxed out.

Also, it should be noted that settlement point 9.d. of the Commission's final order approving settlement in Case No. U-20276 states the following:

> *"To the extent that UPPCO issues additional long-term debt in advance of its next general rate proceeding, UPPCO agrees to provide a benefit-cost analysis of the long-term debt alternatives that the Company evaluated as part of its decision analysis in its next general rate case, including the issuance of long-term debt at UPPCO."*

UPPCO views itself in compliance with this order language because of the approval of the debt restructuring that occurred in Case No. U-20995.

Q. Please describe the debt component of the capital structure at UPPCO *__after__* the sale, as represented in MPSC Case No. U-20995.

A. First, settlement point 2.e. in Case No. U-20995 states the following:

> *"The Proposed Transaction will not impair the ability of UPPCO to raise necessary capital or to maintain a reasonable capital structure. Axium UP should move expeditiously following the issuance of a Commission order approving this settlement agreement to implement its debt refinancing plan as described in the Direct Testimony of Paulo Arencibia."*

Pursuant to this order language, Axium UP moved "expeditiously" to secure the necessary debt refining for UPPCO as further outlined below.

After the sale, the new debt issuance was a 30-year interest-only bond at $127.1 million, which not only paid off the old intercompany loan of $108.2 million, but also any outstanding balance on the short-term credit facility at approximately $15 million. This new debt was issued with an interest rate of 3.59% for 30 years. Further, the Company now has a $75 million revolving credit facility in place to ensure much needed liquidity. Finally, DBRS Morningstar provided a standalone investment grade indicative issuer rating of BBB+ for UPPCO, which it didn't have previously.

Q. Please explain how UPPCO customers benefit from this debt restructure?

A. First, a lower interest rate means lower interest expense. As evidenced in Schedule D1 of Exhibit A-9 (GRH-9) at line 2, UPPCO's new effective cost rate is 4.27% which is 119 basis points lower than the 5.46% long-term debt rate previously paid prior to the debt restructuring. Second, the standalone investment grade credit rating at DBRS Morningstar will assist in providing UPPCO access to capital markets in the future. Third, UPPCO's $75 million revolving credit facility has allowed for much needed liquidity to fund the Company's ongoing operations.

Q. Please explain the relevance of Settlement Point 2i from Case No. U-20995.

A. In MPSC Case No. U-20995, Settlement Point 2i states the following:

> *"UPPCO under its new ownership shall actively manage its permanent capital structure (debt and equity) consistent with the capital structure approved the Commission in the last rate case (U-20276) and address measures intended to reduce the Company's equity percentage in UPPCO's next general rate case to recognize the Staff's and the Attorney General's position for utilities to have a balanced capital structure."*

This order language is relevant because it directionally states that UPPCO is to "*actively manage its permanent capital structure*" such that the Company has a capital structure "*consistent*" with what was approved in UPPCO's last rate case. It also directs the Company to "*address measures intended to reduce the Company's equity percentage*" in UPPCO's next general rate case.

Q. How has the Company managed compliance with Settlement Point 2.i. from Case No. U-20995? Please explain.

A. First, the notion of "*active management*" is important. As evidenced in Schedule D5 of Exhibit A-9 (GRH-13), UPPCO has reduced its equity levels through a purposeful plan of return of capital to UPPHC on a quarterly basis thereby demonstrating active management.

Second, UPPCO has a capital structure that is "*consistent*" with what was approved in its last rate case. For the projected test year, UPPCO is proposing an after-tax WACC of 6.94% with an equity thickness of 53.96%. When directly compared to the approved after-tax WACC of 6.91% and an equity thickness of 54.00%, UPPCO is proposing an after-tax WACC that is 3 basis points higher with an equity thickness 4 basis points lower. Clearly, these values are "consistent" with what was approved in the last rate case.

Third, at the end of UPPCO's first full month of reporting under Axium Infrastructure's ownership, UPPCO's equity level on a FERC reporting basis for the month of July 2021 was $161,517,201 as evidenced in Schedule D5 of Exhibit A-4 (GRH-5) of the historic test year. As evidenced in Schedule D5 of Exhibit A-9 (GRH-13) of the projected test year, the Company's projected June 2024 value of $141,246,647 which is approximately $20 million less thereby demonstrating "*active management*" of its capital structure through "*measures intended to reduce the Company's equity percentage*."

Q. How does UPPCO plan to manage its capital structure on a go-forward basis?

A. Pursuant to the final order approving settlement in MPSC Case No. U-20350, UPPCO is in the process of developing a 62.5 MW solar facility. In the final Commission order approving settlement in this case, settlement point 19.c(1) states the following:

> *"Any new capacity and associated energy that the Company intends to procure through the PCA to replace any of the 125 MW Solar PPA that is cancelled, modified or reduced shall be: (i) acquired through a competitive bidding process consistent with the guidelines in Attachment D to the December 4, 2008 Temporary Order in MPSC Case No. U-15800; and (ii) 50% will be from*

> *PPAs and 50% will be owned by the Company, as acquired through a competitive bidding process. The Company, at its sole discretion, may choose to acquire more than 50% of its new capacity from PPAs."*

This large capital project, which is *not* materially included in this case, will require incremental financing before UPPCO's *next* general rate case. With the anticipated infusion of both equity and debt associated with the solar build, the Company will continue to actively manage its capital structure in general accordance with its approved after-tax WACC.

Q. Please explain how UPPCO is accounting for justifiable IRP-related costs in relation to settlement point 19.c(1), noted above.

A. Pursuant to the final Commission order approving settlement in Case No. U-20350, UPPCO continues to record all justifiable IRP related costs in FERC Account 183. Settlement point 19.i. 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."*

As noted above, since UPPCO is currently in the process of developing its 62.5 MW solar facility, 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.

Q. Please explain how UPPCO has included certain capital project related costs for the 62.5 MW planned solar facility in the Company's projected test year ending June 24, 2024.

A. As evidenced in Exhibit A-45 (GRH-28), AFUDC Calculation, UPPCO is assuming CAPEX spend of approximately $700,623 contingent upon successful and complete execution of necessary contracts.

Q. Please describe the primary drivers causing a decrease in UPPCO's equity balance.

A. As evidenced in Exhibit A-49 (GRH-32), Free Cash Flow, the primary driver of UPPCO's declining equity balance is through a return of capital to UPPCO's parent company, Upper Peninsula Power Holding Company ("UPPHC") from UPPCO.

SECTION XI: INFORMATION TECHNOLOGY CAPEX

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

A. Yes. These projects are evidenced in Exhibit A-52 (GRH-35), Information Technology Projects for 2023-2024.

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

A. It is undeniable that one of the many challenges that businesses face today, including UPPCO, center on keeping existing technologies safe, healthy, and relevant for utility/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, but customers as well.

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 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. Also, further support functions include day-to-day operation support of end-users such as desktop, laptop, and various mobile devices.

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 retail electric rates for the generation and distribution of electricity and other relief.	))))))	**Case No. U-21286**

DIRECT TESTIMONY OF

NATASHA L. WONCH

FOR

UPPER PENINSULA POWER COMPANY

September 8, 2022

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 Manager of 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 Manager of Accounting in 2019.

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 and Energy Waste Reduction ("EWR") reconciliation cases.

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 2021 historical test year revenue requirement ending December 31, 2021 and the calculation of UPPCO's revenue requirement for the projected 12-month period ending June 30, 2024 ("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

2021 Historical Test Year Revenue Sufficiency

2021 Historical Test Year Financial Metrics

2021 Historical Test Year Rate Base

2021 Historical Test year Operating Income

REVENUE REQUIREMENT EXHIBITS

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. For the historical 2021 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:

5. 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.

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 2021 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 2017 through 2021.

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

A. Schedule B1 of Exhibit A-2 (NLW-3) calculates UPPCO's 2021 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 2021 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 2021 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 2021 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 2021 historical test year adjusted net operating income. Page 2 of Schedule C1 of Exhibit A-3 (NLW-7) calculates UPPCO's 2021 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 2021 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 2021 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 2021 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 2021 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 2021 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 2021 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 2021 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 2021 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 2021 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 2021 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.

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 A-2, pages 1 through 3, of Exhibit A-6 (NLW-18).

A. Schedule A-2, 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 (0.70%) as evidenced on line 14.

Schedule A-2, 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: 1.17
    b. With full rate relief: 3.88
2. EBITDA Interest Coverage Ratio, as evidenced on line 25.
    a. Absent rate relief: 2.89
    b. With full rate relief: 5.60
3. Funds Flow from Operations (FFO) Interest Coverage Ratio, as evidenced on line 35.
    a. Absent rate relief: 3.91
    b. With full rate relief: 6.46
4. Overall Fixed Charge Coverage Ratio, as evidenced on line 42.
    a. Absent rate relief: 0.88
    b. With full rate relief: 2.89

Schedule A-2, 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.
    c. Absent rate relief: Not applicable, no common dividends.

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

3. Permanent Capitalization, as evidenced on line 55.

e. Absent rate relief: $276,063,979

f. With full rate relief: $276,063,979

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 $352,308,859, and the projected test year Michigan retail rate base is $348,730,362, 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 2021 actual balance of utility plant was projected forward using UPPCO's projected 2022 through 2024 construction budgets. The projected test year total company utility plant is $451,477,222, and the projected test year Michigan retail utility plant is $446,052,695, 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 2021 actual balance of accumulated provision for depreciation was projected forward using UPPCO's 2022 through 2024 construction budgets. The projected test year total company accumulated provision for depreciation is $191,322,665, and the projected test year Michigan retail accumulated provision for depreciation is $188,849,174 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 $92,154,302, and the projected test year Michigan retail working capital is $91,526,841 as shown on line 38. 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 $7,319,520 and the projected test year Michigan retail adjusted net operating income is $7,320,589 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 1.3466.

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 $109,034,335, and the projected test year Michigan retail total revenue is $108,248,744 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 $35,853,764 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 $39,935,577 and the projected test year Michigan retail total O&M expense is $39,464,178 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 $14,646,530, and the projected test year Michigan retail total depreciation and amortization expense is $14,452,811 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 $8,617,314, and the projected test year Michigan retail total taxes other than income taxes is $8,514,290 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 ($347,556), and the projected test year Michigan retail income taxes are ($336,432) as shown on line 15. These amounts include the remaining 10 months amortization of the Tax Cut and Jobs Act of 2017 ("TCJA") Calculation C as approved in UPPCO's last general rate case, U-20276. The TCJA Calculation C total amount is $4,696,289.65 and was amortized over 5 years, beginning June 2019.

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 ($54,210) and the projected test year Michigan retail state income taxes are ($47,600) as shown on line 15.

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 ($40,063) and the projected test year Michigan retail AFUDC Debt is ($39,626) as shown on line 5. Exhibit A-45 (GRH-28), AFUDC Calculation, provides supporting evidence of this calculation.

2021 HISTORICAL TEST YEAR REVENUE DEFICIENCY (SUFFICIENCY)

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

A. Schedule A-1 of Exhibit A-1 (NLW-1) calculates UPPCO's historical 2021 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 2021 total company revenue sufficiency is ($2,161,688), and the 2021 Michigan retail revenue sufficiency is ($2,617,362). As shown on the schedule, the component parts are taken form the various sources indexed to the left of each value.

2021 HISTORICAL TEST YEAR FINANCIAL METRICS

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

A. Schedule A-2, page 1 of Exhibit A-1 (NLW-2) depicts financial metrics on a financial basis for 2017 through 2021. For this period, UPPCO's earned rate of return on common equity was (3.13%), 4.39%, 6.19%, 7.58%, and 9.36% as seen on line 12.

Schedule A-2, page 2 of Exhibit A-1 (NLW-2) depicts additional financial metrics on a financial basis for 2017 through 2021, 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 A-2, page 3 of Exhibit A-1 (NLW-2) depicts additional financial metrics on a financial basis for 2017 through 2021, 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 A-2, page 4 of Exhibit A-1 (NLW-2) depicts additional financial metrics on a ratemaking basis for 2017 through 2021. For this period, UPPCO's earned rate of return on common equity was 6.07%, 5.85%, 8.18%, 9.05%, and 8.53% as seen on line 73.

Schedule A-2, page 5 of Exhibit A-1 (NLW-2) depicts additional financial metrics on a ratemaking basis for 2017 through 2021, 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 A-2, page 6 of Exhibit A-1 (NLW-2) depicts additional financial metrics on a ratemaking basis for 2017 through 2021, 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.

2021 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 2021 historical test year rate base. The 2021 total company rate base is $298,915,316, and the 2021 Michigan retail rate base is $295,726,464, 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 2021 historical test year utility plant. The 2021 total company utility plant is $389,496,181, and the 2021 Michigan retail utility plant is $384,635,510, 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 2021 historical test year accumulated provision for depreciation. The 2021 total company accumulated provision for depreciation is $163,495,936, and the 2021 Michigan retail accumulated provision for depreciation is $161,319,253 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 2021 historical test year working capital. The 2021 total company working capital is $72,915,071, and the 2021

Michigan retail working capital is $72,410,207 as shown on line 38. All values shown are 13-month averages.

2021 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 2021 historical test year adjusted net operating income. The 2021 total company adjusted net operating income is $18,236,953 and the 2021 Michigan retail adjusted net operating income is $18,354,991 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 2021 historical test year gross revenue conversion factor. The 2021 gross revenue conversion factor is 1.3466.

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

A. Schedule C3 of Exhibit A-3 (NLW-9) calculates UPPCO's 2021 historical test year total revenue. The 2021 total company revenues are $113,755,762, and the 2021 Michigan retail total revenue is $112,814,646 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 2021 historical test year total fuel and purchased power cost of $35,853,764 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 2021 historical test year total O&M expense, exclusive of fuel and purchased power. The 2021 total company O&M expense is $36,385,453 and the 2021 Michigan retail total O&M expense is $35,950,196 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 2021 historical test year total depreciation and amortization expense. The 2021 total company total depreciation and amortization expense is $12,011,547, and the 2021 Michigan retail total depreciation and amortization expense is $11,851,600 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 2021 historical test year total for taxes other than income taxes. The 2021 total company total taxes other than income taxes is $7,904,065, and the 2021 Michigan retail total for taxes other than income taxes is $7,805,464 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 2021 historical test year federal income taxes. The 2021 total company federal income taxes are $2,326,077, and the 2021 Michigan retail income taxes are $2,288,177 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 2021 historic test year state income taxes. The 2021 total company state income taxes are $719,630 and the 2021 Michigan retail state income taxes are $710,676 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 2021 historical test year local taxes. The 2021 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 2021 historic test year AFUDC. The 2021 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 retail electric rates for the generation and distribution of electricity and other relief.	))))))	**Case No. U-21286**

DIRECT TESTIMONY OF

STEPHEN S. LILLIE

FOR

UPPER PENINSULA POWER COMPANY

September 8, 2022

QUALIFICATIONS

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

A. My name is Stephen S. Lillie. My business address is 500 North Washington Street, Ishpeming, MI 49849. I am the Director of Distribution 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 received a Bachelor of Science Degree from DeVry Institute – Lombard, IL in 1985. I began my career with UPPCO in 1988 as an Engineering Aide responsible for standard distribution system design as well as design, oversight, and inspection of specialized electric distribution construction related to the U.S. Navy's "Project E.L.F." Antenna Operations. Since then I have worked in various positions over almost 34 years all dealing with electric distribution system design, operations, metering, engineering, and oversight, such as Mitigation Coordinator, Customer Service Coordinator, Customer Service Manager and Operations Manager overseeing both line, metering, and engineering operations.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to outline and provide support for UPPCO's overall system capital improvements covering distribution system hardening and reliability, substation, generation, fleet and facilities projects. I also outline and provide support for proposed changes to UPPCO's vegetation management line clearance program.

EXHIBITS

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following Exhibits:

- Schedule B5 of Exhibit A-7 (SSL-1)
- Schedule B5.1 (Pages 1 & 2) of Exhibit A-7 (SSL-2)
- Schedule B5.4 of Exhibit A-7 (SSL-3)
- Schedule B5.5 of Exhibit A-7 (SSL-4)
- Schedule B-5.6 of Exhibit A-7 (SSL-5)

I am sponsoring the following exhibits:

- Exhibit No. A-26 (SSL-6), UPPCO Capital Expenditures (CAPEX) by Business Line
- Exhibit No. A-27 (SSL-7), UPPCO Facility CAPEX
- Exhibit No. A-28 (SSL-8), UPPCO Substation CAPEX
- Exhibit No. A-29 (SSL-9), UPPCO Generation CAPEX
- Exhibit No. A-30 (SSL-10), UPPCO Distribution Reliability CAPEX
- Exhibit No. A-38 (SSL-11), 6 Year Distribution Line Clearance Program

Q. Please describe Schedule B5 of Exhibit A-7 (SSL-1).

A. Schedule B5 of Exhibit A-7 provides a summary of the Company's actual and projected capital expenditures by type for the 2021 historic test period ("historic test year"), the bridge period of January 2022 through June 2023 ("projected bridge period"), and the projected test period from July 1, 2023 through June 30, 2024 ("projected test year"). As evidenced at line 9 of this Exhibit, the Company's total projected capital expenditures for the projected test year total $34.044 million. The Company's investment in these areas illustrate UPPCO's continued focus on reliable and safe generation and delivery of energy to its customers.

Q. Please describe Schedule B5.1 (Pages 1 & 2) of Exhibit A-7 (SSL-2).

A. Schedule B5.1 (Pages 1 & 2) of Exhibit A-7 provides a summary of the Company's actual and projected capital expenditures related to generation by business driver and facility for each year for the historic test year, projected bridge period, and projected test year. As demonstrated at line 7 of Page 1, actual 2021 capital expenditures for power generation totaled $1.643 million. Also, projected test year capital expenditures total $3.066 million. The same values are broken down by production facility at line 17 of Page 2 of this same exhibit.

Q. Please describe Schedule B5.4 of Exhibit A-7 (SSL-3).

A. Schedule B5.4 of Exhibit A-7 provides a summary of the Company's actual and projected expenditures by business driver (i.e., improve reliability & load growth, new equipment & equipment upgrade, new customers & services, contractual & statutory and special projects) for distribution and substation for the historic test year, the projected bridge period, and the projected test year. Each of these line items is forecasted based on the scope of intended projects and current information known about that line item.

As demonstrated at line 7, actual 2021 capital expenditures for distribution totaled $10.404 million. Projected test year capital expenditures for distribution total $16,083 million. Company Witness Ringler will speak to and provide additional support for the largest business driver in this category, improve reliability and load growth. In this business driver, I will identify the total of blanket/routine capital projects less than $50,000 and I will identify each project greater than $50,000.

As demonstrated at line 13, actual 2021 capital expenditures for substation totaled $3.354 million. Projected test year capital expenditures for substation total $5.208 million.

In total, as demonstrated at line 14, actual 2021 capital expenditures for distribution and substation totaled $13.759 million. Projected test year capital expenditures for distribution and substation total $21.291 million.

Q. Please describe Schedule B5.5 of Exhibit A-7 (SSL-4).

A. Schedule B5.5 of Exhibit A-7 provides a summary of the Company's actual and projected expenditures by business driver (i.e., meters, field area network, project preparation, and information technology) for advanced metering infrastructure for the historic test year, the projected bridge period, and the projected test year. As evidenced at line 7, projected test year capital expenditures related to advanced metering infrastructure total $2.073 million.

Q. Please describe Schedule B5.6 of Exhibit A-7 (SSL-5).

A. Schedule B5.6 of Exhibit A-7 provides a summary of the Company's actual and projected capital expenditures for corporate from historic test year, projected bridge period, and projected test year. The items on lines 3 and 4 covering Fleet and Facility expenditures, respectively, are forecasted based on the scope of intended projects and current information known about those line items. As demonstrated at lines 6, actual historic test year capital expenditures for corporate and general plant totaled 4.590 million. Projected test year corporate and general plant capital expenditures total 9.686 million, as evidenced at line 6.

Q. Please describe Exhibits A-26 (SSL-6) through Exhibit A-30 (SSL-10).

Exhibit A-26 (SSL-6), UPPCO Capital Expenditures (CAPEX) by Business Line, provides a summary level depiction of the Company's actual and projected expenditures by business driver from 2021 through the projected test year. Each of these line items is forecasted based on historical values, scope of intended projects, and other current information known about that line item.

Exhibit A-27 (SSL-7), UPPCO Facility CAPEX identifies all the facility projects for 2023 and the 2024 projected test year broken down into blanket/routine totals for projects less than $100,000 and individual totals for facility projects greater than $100,000. As demonstrated at line 7 of this exhibit, UPPCO's projected capital spend for calendar years 2023 and 2024 is totals $1.063 and $1.329 million, respectively.

Exhibit A-28 (SSL-8), UPPCO Substation CAPEX, identifies all the substation projects for 2023 and 2024 projected test year broken down for projects greater than $100,000. As demonstrated on line 17 of this exhibit, UPPCO's projected capital expenditure for calendar years 2023 and 2024 totals $3.851 and $4.379 million, respectively.

Exhibit A-29 (SSL-9), UPPCO Generation CAPEX, identifies all the projects for generation facilities that are greater than $100,000. As demonstrated at line 15 of this exhibit, UPPCO's projected capital expenditures for calendar years 2023 and 2024 totals $2.766 and 2.108 million, respectively.

Exhibit A-30 (SSL-10), UPPCO Distribution Reliability CAPEX, identifies all the projects in the improved reliability and load growth business driver category for projects greater than $50,000 that are planned for the 2023 and 2024 calendar years. The purpose of including UPPCO's intended 2023 and 2024 distribution capital projects is that due to resource planning and optimization, UPPCO may decide to push and or pull certain projects from into or out of the projected test period. UPPCO intends to manage to the yearly summed distribution capital expenditure values as demonstrated at line 35, which for 2023 is estimated at $15.246 million, and for 2024 is projected at $16.320 million. As evidenced at line 3 of Exhibit A-7 (Schedule B5.4), UPPCO's projected test year capital expenditures related to distribution reliability totals 9.021 million. Company Witness Ringler addresses UPPCO's approach to managing distribution system reliability, including the identification and prioritization of distribution system hardening and reliability projects in his direct testimony.

Q. Please describe Exhibit A-38 (SSL-11).

A. Exhibit A-38 (SSL-11) provides a summary of UPPCO's six-year distribution line clearance program.

Q. As outlined in your testimony, do you believe the capital projects that constitute UPPCO's projected test year capital expenditures are just and reasonable?

A. Yes. As evidenced in Exhibit A-27 (SSL-1) and Exhibit A-7 (Schedule B5) the capital spending levels are generally consistent with UPPCO's recent historical data with a modest increasing trend in alignment with Governor Whitmer's increasing focus on distribution system hardening and reliability, as well as ensuring that a utility's proposed actions and investments in distribution reliability projects are sufficient to withstand the increasing severity of the storms experienced within the region. As evidenced in Exhibit A-27 (SSL-6) on line 27, column H, UPPCO's projected test year capital expenditures excluding special projects is approximately 15% more than the two-year average. And, as evidenced in line 27, column J, UPPCO's projected test year capital expenditure is approximately 28.7% higher than the three-year historical average. As demonstrated in my testimony as well as within the testimony of Company Witness Ringler, UPPCO has applied a rigorous approach to identifying and prioritizing its distribution capital projects.

Q. Please describe the current market conditions relating to the cost of utility materials and describe the resulting impact on the cost incurred by the Company.

A. Recently, the supply and cost of typical utility materials and equipment have been impacted by a variety of labor, fuel, and material market price conditions, which have caused the price of these items to increase at a pace well beyond historical inflationary trends. The direct result of these factors is that there is significant upward pressure on related UPPCO construction and material costs. UPPCO has expended considerable effort in an attempt to mitigate these higher-than-normal inflationary increases, and in certain instances, to preserve the ability to procure the necessary equipment at all. The impact of this issue is vast across the utility (and other) industry, and is certainly not unique to UPPCO as it has been evidenced in all manner of news and other information sources, as well as in conference with our utility industry peers. Supply chain disruptions have affected the availability of many core base materials which go into the manufacture of items such as line hardware, wire, underground conductor and conduit, and in particular, transformers, creating both lead time and significant pricing impact and volatility throughout the electric and other such industries at a magnitude not seen before in my career. As evidenced at Line 28 of Exhibit A-30, standard distribution line transformer costs have almost quadrupled in recent months, while at the same time, the required manufacturer lead times has been extended from the historical average of 12 to 16 weeks to now, in some cases, two to three years. As market conditions begin to slowly stabilize within the realm of supply chain and production rates, along with increased flow of raw materials needed for the manufacturing process, it is hoped that this significant level of price volatility experienced by UPPCO recently will subside to pre-pandemic levels. However, UPPCO expects that these conditions will continue to impact the Company's material and construction costs through the duration of the projected test year.

DISTRIBUTION LINE CLEARANCE PROGRAM

A. Please describe UPPCO's line clearance program.

Q. UPPCO has approximately 2,200 miles of overhead 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 ways 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 / 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 right of ways that are in rural areas, that are becoming unidentifiable and that are inaccessible for operation and maintenance.

Q. Has UPPCO successfully completed the directives regarding cycle line clearance in accordance with paragraph 9(h) of the Commission's Order approving settlement in MPSC Case No. U-20276?

A. Yes. From 2019 through 2021, UPPCO cleared the following line miles: 374.6 (2019), 381.8 (2020) and 376.4 (2021).

Q. In calendar years 2023 and 2024, how many line miles will UPPCO be targeting for its distribution line clearance program?

A. As stated above, UPPCO intends to continue its 6-yeaer vegetation management cycle in compliance with the Commission's prior direction and is targeting a trim of no less than

372-line miles per year at a cost of approximately $3.149 million in the projected test year. Please see Exhibit A-38 (SSL-11), 6-Year Distribution Line Clearance Program.

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 right of ways 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. 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, and 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 projected for the 2023 and 2024 calendar years are approximately 69% greater than the equivalent values experienced in 2019 at the time of UPPCO's last general rate case, Case No. U-20276.

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 required annual line clearance miles. 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. Is the Company's proposed vegetation management program and projected costs for the projected test year reasonable, and consistent with sound utility principles?

A. Yes.

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 retail electric rates for	)	**Case No. U-21286**
the generation and distribution of	)	
electricity and other relief.	)	
	)	

DIRECT TESTIMONY OF

JAY R. RINGLER

FOR

UPPER PENINSULA POWER COMPANY

September 8, 2022

QUALIFICATIONS

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 Manger of Distribution Engineering 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. 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, and later to Technical Services Manager. My current position as UPPCO's Manager of Distribution Engineering began in May 2015.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my 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-31 (JRR-1), 2017-2021 Reliability Indices
2. Exhibit No. A-32 (JRR -2), 2017-2021 Major Event Days
3. Exhibit No. A-33 (JRR -3), 2017-2021 Outages by Cause
4. Exhibit No. A-34 (JRR -4), 2017-2021 Pole Inspection History
5. Exhibit No. A-35 (JRR -5), 2017-2021 Underground Inspection History
6. Exhibit No. A-36 (JRR -6), 2017-2021 Underground Outage History
7. Exhibit No. A-37 (JRR -7), 2023-2024 System Hardening & Reliability Projects

Q. How is your testimony organized regarding distribution system reliability?

A. My testimony is organized as follows:

- Distribution System Conditions
- Reliability Metrics and System Goals
- Local System Load Forecasts

- Maintenance and Upgrade Plans
- Capital Expenditure Decision Criterion
- Customer Value Analyses
- List of Capital Projects

DISTRIBUTION SYSTEM CONDITIONS

Q. Please provide an overview of UPPCO's distribution system conditions.

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'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 2,180 miles of primary, 620 miles of secondary, and 540 miles of service line. The underground lines consist of approximately 770 miles of primary, 40 miles of secondary, and 350 miles of service line. 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 12 customers 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 38 years. The expected life of a typical utility pole is 40-years. Currently, 35% of UPPCO's poles are of the 1970-1979 vintage, making these poles 43-52 years old, which is beyond the expected life. Poles weaken with age and are more likely to fail during storm conditions.

A significant amount of the underground cable was installed in the 1970's 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.

RELIABILITY METRICS AND 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. System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index (" SAIFI "), and Customer Average Interruption Duration Index ("CAIDI") are often used to compare performance among utilities.

As evidenced in Exhibit A-31 (JRR-1), 2017 – 2021 Reliability Indices, UPPCO's 5-year reliability data is shown for All Weather conditions and Excluding Major Event Days ("MEDs"), which was filed with the MPSC on April 14, 2022.

Please note, UPPCO removes transmission-caused outages from its filed reliability indices calculations based on language in IEEE 1366-2012, Section 5.2, 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.

In 2013, the State set goals for reliability in Michigan, which equated to a SAIDI of less than 150 minutes per year and a SAIFI of no more than 1 event per year. Since then, the 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 2021 was 163 minutes and for 2022 is 160 minutes.

In 2021, excluding transmission-caused events and MEDs, UPPCO’s SAIDI was 149 minutes and SAIFI was 1.2 events per average UPPCO customer. However, including MEDs, UPPCO’s 2017-2021 5-year average SAIDI was 394 minutes, and UPPCO’s SAIFI was 1.8 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-32 (JRR-2), MEDs, UPPCO represents the Threshold for a Major Event Day (“TMED”) from 2017-2021 as well as the number of MEDs per year. Please note that there was only one MED in 2020 and 2021, but five in 2017 and in 2019. So, although MEDs are removed from the data, there is overlap of outages on the adjacent days before and after a MED which are not included in the MED, since MEDs occur from midnight to midnight, statistically, regardless of when the storm actually started. Partial storm days may or may not meet the threshold of a MED, but in UPPCO’s experience, the MED has been for one calendar day even though storm restoration efforts may continue into the following days. Comparing 2017 data to 2021, excluding MEDs, the data indicate that UPPCO's reliability is improving, and its metrics are on a downward trend. This, in part, is due to UPPCO achieving a 6-year line clearance cycle after the accelerated line clearance program was completed from 2014-2017. However, the decline has not been a straight line over this period and shows an increase in 2019 and 2020. 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 TMED of 17.4 minutes. Therefore, small differences in the daily SAIDI can have a big impact on the cumulative SAIDI over the course of a year. UPPCO's continued capital expenditures for storm hardening and reliability improvements will continue to reduce UPPCO's SAIDI over time.

As evidenced in Exhibit A-33 (JRR-3), Outages by Cause, UPPCO depicts the 5-year average from 2017-2021 of all the outages by cause. Looking at all-weather events, weather-related outages represent the highest percentage of causes in terms of SAIDI minutes at 38%, followed closely by tree-related causes at 36%; however, when excluding MEDs and transmission-caused events, the tree-caused outages rise to 44% in terms of SAIDI minutes. In addition, in terms of the number of outage events, tree-related outages top the list under both all-weather and excluding MEDs and transmission-caused events.

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 2012 to 2021 was 0.4%.

MAINTENANCE AND 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-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 now maintains 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 our wire environment 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 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. Enhance 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.

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 both foreign-owned poles as well as those that are self-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 2017 to 2021, an average of 2.3% 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-34 (JRR-4), 2017 – 2021 Pole Inspection History. As seen in this table, the 5-year average cost for the professional overhead system inspection and pole treatment was approximately $160,500 per year or roughly $25 per pole. The 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-35 (JRR-5), 2017 – 2021 Underground Inspection History. As seen in this table, the 5-year average cost for the professional underground system inspection was approximately $72,900 or roughly $48 per cabinet. Additionally, 111 cabinets were refinished over this period, extending the life of these assets, at a cost of $30,200, or roughly $272 per cabinet. These on-going maintenance activities need 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 1970's 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 undergrounding") 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 outage causes, including underground distribution equipment failures. As evidenced in Exhibit A-36 (JRR-6), Underground Outage History Compared to All Outages, the number and impact of underground related events is an order of magnitude less than all other events. For all outage events, excluding transmission-caused, over the period of 2019-2021, UPPCO experienced 6,255 events affecting 328,499 customers resulting in a SAIDI of 1,262 minutes. Outages attributed to underground equipment failures involving pad-mount transformers or conductors, and dig-ins, accounted for only 108 of those events affecting 586 customers resulting in a SAIDI of 1.8 minutes. So, less than 2% of all outages and less than ½% of customers who experienced outages were due to underground-related events compared to outages caused by all other events.

Q. Does undergrounding decrease maintenance costs?

A. Yes. In the Company's response filed in Case No. U-21122, UPPCO noted the maintenance costs of underground compared to overhead. Approximately 74% of UPPCO's 4,500 total electric line miles are configured as overhead conductor and the remaining 26% of the total line miles as underground. UPPCO's maintenance costs for calendar years 2019 and 2020 were $6.6M and $5.8M, respectively. In both years, overhead accounted for 93% of the total maintenance expenditure, while underground maintenance accounted for only 7%, resulting in underground maintenance costs of about $398 per mile compared to overhead at about $1,838 per mile in 2019 and $350 per mile for underground in 2020 compared to $1,615 per mile for overhead. The maintenance costs described above are attributable to activities such as: trouble calls/callouts, line clearance activity, inspection programs, locating, and asset refurbishment, among others.

Q. Does strategic undergrounding increase customer value?

A. Yes. Replacement of overhead lines with underground provides value to UPPCO customers in several ways. As mentioned in reference to Exhibit JRR-6 above, underground outages account for less than 2% of the total number of outages, so customers receive a significant improvement in reliability indices with and underground system. 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. I will illustrate this by taking one example from UPPCO's 2023 System Hardening and Reliability Projects list. The "OSC 719 Jacobsville Rd" project will replace 32,500ft of 1-phase overhead with underground at an estimated cost of $700,000 benefitting 240 customers, which results in a cost of $2,917 per customer. Since UPPCO's service territory consists of about 12 customers per mile and based on the maintenance costs in 2019 and 2020, the average cost to maintain overhead was $1,727 per mile or about $144 per customer, versus underground, which was $374 per mile or about $31 per customer, for a savings of $113 per customer with underground. So, in 26 years, the savings in maintenance costs outweigh the cost of the converted line per customer served for this project. Other projects have different levels of return based on the cost of the project and the number of customers served, and some projects are necessary to replace aged facilities and maintain the system in a safe state.

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, lodging, loss revenue to business, etc., all are dependent on various factors, such as demography, outage duration, ambient temperature, customer actions, and even customer expectations. That being said, in U-20629, the Citizen's Utility Board ("CUB") suggested that outages may cost the average customer $3-4 per hour. 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 3-year SAIDI, including MEDs, reported in Exhibit JRR-6 was 1262.5 minutes, for an average of 421 minutes, or 7 hours per customer per year for all outages, but only 1.8 minutes, for an average of 0.6 minutes, or 0.01 hours per customer per year for underground-related events. Assuming a customer cost of $3.50 per hour, each customer would save $24 per year. So, in the Jacobsville Project example above, the project would present an average customer cost savings of $5,760 per year for the life of the installed assets. These are unrealized savings since they are avoided costs as a result of reduced outages, but these unrealized savings represent another value to customers from 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. The method to strategically target replacement of specific areas of the system is described later in my testimony.

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 UPPCO's Enhanced Restoration process.

A. UPPCO enhances the restoration process 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. This strategy was discussed in UPPCO's response to U-21122 regarding storm damage in August 2021 in the Commission's questions regarding back-lot versus front-lot construction and maintenance costs. UPPCO see the significant value in reliability improvement and reduction in future maintain costs of moving overhead off-ROW lines to an on-ROW underground system. 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 out until the system could 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 outaged. This improves efficiencies with dispatching resources and aids in diagnosing system issues.

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 reviews the 2 to 5-year outage history for the whole company to help prioritize capital improvements by feeder. 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 maximum number of points. UPPCO has 80 feeders in the 5-year data set, so the worst feeder in each category is assigned 80 points and the best feeder assigned 1 point. The points are added for each of the four measures, and the feeder with the most 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 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.

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 Michigan Public Service Commission ("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 MPSC's Distribution Performance Measures requirements, 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.

SYSTEM HARDENING AND RELIABILITY PROJECTS ("SHARP")

Q. Please 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's project classification system is as follow: R – Reliability/Storm Hardening; A – Age & Condition; S – Safety; C – Compliance/Voltage; and L – Load/Capacity. For the July 2023 to June 2024 projected test year, UPPCO is planning to implement the projects as evidenced in Exhibit A-37 (JRR-7), 2023 – 2024 System Hardening and Reliability Projects. The identification of these projects ultimately informs UPPCO's improve reliability and load growth component of the Company's distribution CAPEX plan.

SHARP – CAPITAL PROJECT DESCRIPTIONS

Q. Please describe SHARP project, BRM 1231 Reliability Part 1, North Basin 1-ph OH to UG.

A. From 2018 – 2021 Barnum 1231 ranked at the #1 worst feeder in terms of reliability. This is a move up from #11 from 2013 – 2017. Customers at the end of the line on North Basin Drive experience every outage associated with upstream faults, including two on the tap fuse feeding this section over the past two years. This project will install approximately 5,700ft of 1/0 underground, replacing existing overhead line serving 118 customers.

Q. Please describe SHARP project, DLT 589 Ford River Reliability Part 1, 1-ph OH to UG.

A. Delta 589 was the 10th worst feeder in 2020-2021. The existing overhead lines serving this area are not accessible by truck or tracked vehicle as the ROW is very narrow and wet. The line is not straight so it must be walked to determine cause of the outage. Additionally, the poles are set shallow due to rock ledge, making them dangerous to climb. This project removes 2,600ft of #6 solid copper overhead thru hard-to-access, cedar swamp ROW and installs 4,100ft of primary underground installed along M35 closes the H road loop, making for easy isolation of faults on H road. This project will also create a loop and benefit 63 customers. An 1,800ft primary underground tap down the driveways will be installed for future accessibility to serve the customers.

Q. Please describe SHARP project, FRE 203 35kV system improvements Part 1.

A. Freeman 203, otherwise described as the Lindberg tap, serves only 18 customers and is one of the oldest lines on the system (1951 easement date). Primarily industrial in nature, FRE 203 serves the Marquette County Landfill, a communication tower, two gravel pits, and 5 residential customers, running cross country three miles before serving any customers. Access to the overhead line is via snowmobile/ATV trails necessitating off-road equipment which is often needed in other locations during inclement weather. As a result, restoration times are excessive and the work is difficult for the crews given the extremely rugged terrain, including rivers, which cannot be traversed. The three-phase line consists of a one-mile section of solid copper conductor on aged lattice towers before switching to wooden poles and stranded copper. The line is prone to tree contacts, galloping, and snow loading which often causes downed lines on the snowmobile/ATV trail resulting in a dangerous situation for the public. The line traverses the gravel pit creating safety hazards with the heavy equipment and piles of rock/gravel. Blasting activities also impact the reliability of the line through equipment damage from flying rock and concussive forces. Underground is not an option in the gravel pit due to the excavation activities. Unique easement situations in the gravel pit make the route of the line subject to change by the property owner, thus creating the potential for extensive line relocation costs. This project will consist of easement and surveying work to replace the 1951 easement route, achieving a permanent ROW and more accessible route. Also included in Part 1 is the replacement of the 1 mile of steel lattice towers and solid copper conductor with three-phase underground.

Q. Please describe SHARP project, KI/LL Tie Part 2, 3-ph OH to UG.

A. This project is Part 2 of a 2021 project to rebuild the overhead line connecting KIS 1275 & GWN 657 (Little Lake circuit). Part 1 was required to prevent outages to over 1,561 KIS 1275 residential customers on two days for 10 hours due to ATC maintenance activities. Relocation of the overhead powerline to underground facilities in road ROW will reduce outages and eliminate the potential for fire associated with off-road overhead powerlines in heavily wooded areas. The tie will be capable of serving the KIS 1275 'Residential circuit' load thus creating a backfeed for one of UPPCO's most customer-dense areas. KI Sawyer substation is radially fed off an ATC 69kV transmission, so backfeed capability is beneficial for serving customers during a transmission outage. This project is 1.75 line-miles of 3-phase of 4/0 underground (about 28,000ft of cable) with 10 junctions.

Q. Please describe SHARP project, FRY 2733 Shag/Charlie Lakes UG Part 2, 1-ph/2-ph OH to UG.

A. From 2018 – 2021, Gwinn 653 (now FRY 2733) was the 4^{th} worst feeder in UPPCO's service territory. The Shag Lake tap on this line is a significant area of excessive CAIDI minutes. The Shag Lake tap is a two-phase (partially copper) overhead line, protected by a recloser, serving 285 customers. From 2018 – 2020, the upstream recloser serving the Shag Lake tap tripped 4 times with respective restoration times of approximately 8.1, 9.7, 23.7, and 26.5 hours. Rugged conditions require on-foot damage assessment and repairs using a tracked vehicle contributing to the excessive restoration times and significant man-hours. UPPCO installed Part 1 of this project in 2022. Part 2 will replace aged overhead conductor with approximately 3,700ft of 1/0 underground and close a gap to create a loop to the new underground powerline installed in Part 1.

Q. Please describe SHARP project, PLK 401 Reliability Part 1, 1-ph OH to UG Witch Lake

A. Over the 5-year period of 2013-2017, Perch Lake circuit 401 was the worst rated feeder in UPPCO's service territory and was ranked the #1 worst feeder again over the years 2020-21. with a SAIDI of 33 minutes and a total of 141 outages over the past 2 years. The 56 customers served off the single-phase overhead tap feeding south of Witch Lake experienced 10 outages over the past 2 years, two of which were from the tap fuse serving this section. This project will convert aged overhead line to underground from Fence River Road/Witch Lake south to the end of the single-phase, approximately 2.25 miles.

Q. Please describe SHARP project, PLK New 12kV Feeder & Tie Switches.

A. This project supports a planned substation project, which will improve the ability to restore power in a loss of bay scenario at the substation. The substation project will construct new feeders from a new transformer bay and then will rebuild one feeder in the old transformer bay, resulting in an additional feeder at the Perch Lake Substation. The distribution project will install new tie point and switches outside the substation to allow for the substation work and will also allow for faster restoration of service to customers in the event of future feeder outages. The third feeder at this substation will allow for a better division of customers among the three circuits, thereby reducing the number of customers affected by outages on any one of the feeders. This project serves nearly 1,400 customers.

Q. Please describe SHARP project, M38 747 Copper replacement on M38 Part 2, 3-ph OH to UG.

A. M38 747 had the #4 worst SAIDI in 2020-21, and the Alston-Nisula area was the biggest contributor to this poor performance. Alston-Nisula consists of 360 customers and has experienced long outages over the past 3 years. UPPCO facilities serving these customers are old copper wire located in areas that are difficult to access for repairs. Additionally, the system is 2-phase and does not allow the opportunity as currently built to balance load to improve voltage and limit outages to a smaller number of customers. A 2022 project began converting the two-phase copper overhead wire along M38 to three-phase underground cable. Phase 2 of this project will continue this undergrounding and improve reliability to an area of the system that had a SAIDI of 11.40 over the past 3 years. This project will install approximately 16,500ft of three-phase 4/0 cable, twelve 3-phase junction boxes, 4 fuse pads, and 5 padmount transformers, and remove 2 phase copper underbuilt on the Prickett Dam circuit.

Q. Please describe SHARP project, KWN 927 Copper Harbor to Mtn. Lodge 3-ph Rebuild.

A. KWN 927 had the #1 worst SAIDI and SAIFI in 2020-21. Extended travel time is needed to reach this area. and vegetation issues exist at all areas of this feeder. This area is also rocky, providing limited access to the existing facilities. The end of the feeder from Copper Harbor to the Mt. Lodge is copper wire that was installed in 1977, and the 112 customers served by this portion of the line experienced at least 18 outages during 2018-2021. This project will convert these facilities from overhead to underground or rebuild to taller class 3 poles depending on ground conditions, i.e., rocky terrain. This project will install approximately 6,500ft of three phase 4/0 cable and up to four 3-phase junction boxes (if all underground) or up to 43 new poles (if all overhead).

Q. Please describe SHARP project, OSC 719 Jacobsville Rd 1-ph OH to UG conversion from Dreamland to Rabbit Bay Rd.

A. OSC 719 had the #4 worst SAIDI and #7 worst SAIFI and the #4 worst feeder in 2020-21. The Jacobsville and Rabbit Bay area of the Lake Linden circuit consists of 239 customers, who have experienced the most frequent outages over the past 3 years. UPPCO facilities serving these customers are old copper wires that have frequent issues with vegetation. By converting the copper overhead wire from Dreamland to Rabbit Bay Rd to underground cable, UPPCO will be improving reliability to an area of the system that has experienced 17 outages and had a SAIDI of 9.12 over the past 3 years. This project will install single phase 1/0 cable approximately 32,500ft, fifteen 1-phase junction boxes, 10 fuse pads, and 12 padmount transformers, and remove the existing overhead system.

Q. Please describe SHARP project, OSC 717 Relocate Mohawk to Highway 3-ph Part 2.

A. OSC 717 leaves the road right of way for 1.25 miles between Ahmeek and Mohawk. This makes the facilities difficult to access, and the 548 customers served by these facilities are consequently exposed to extended outages due to vegetation issues. The reliability of this feeder will be improved by relocating existing facilities from this cross-country section to the highway ROW for improved access. Part 1, which began in 2022, relocated 2,500ft of this line. Part 2 will extend approximately 4,000ft of 3-phase 1/0 conductor from the end of the Part 1 project and remove the existing off right-of-way poles and conductor.

Q. Please describe SHARP project, ELE 1121 Point Mills OH to UG 1-ph conversion.

A. From 2013-2017, 17 customers served by ELE 1121 have experienced 27 outages. From 2018-2021 these same customers experienced 21 outages. 18 of these outages have been traced back to three fuses that serve small segments of overhead line that are surrounded by underground wire. Most of these 18 outages have been caused by animal contact or other unknown causes. Reliability will be improved by converting the overhead segment to underground. This project will install 1-phase, 1/0 underground cable approximately 3,500ft, and remove existing overhead facilities.

Q. Please describe SHARP project, BRM 1231 Reliability Part 2 South Camp Rd.

A. From 2018-2021 Barnum 1231 was UPPCO's worst performing feeder. With an increasing number of year-round residents, this off-road tap crosses customer septic systems and drain fields. This area is prone to excessive snowfall and poor access in winter months, making outage restoration times excessive and resource intensive. This project will install approximately 12,500ft of 1/0 underground in easements along a private road and close a gap to another tap to establish a loop for future maintenance and outage restoration activities.

Q. Please describe SHARP project, DLT 589 Ford River Reliability Part 2.

A. This project relocates the line to M35 ROW. Sections of the current overhead lines are not accessible by truck or tracked vehicle, as they cross multiple customer septic systems and drain fields. The line is located close to the lake and frequently experiences galloping, creating nuisance outages and momentary outages to 39 customers. Additionally, the poles are set shallow due to rock ledge, making them dangerous to climb. This project will install 3,625ft of 1/0 underground in M35 ROW and 2,000ft of additional conductor down driveways where easement can be obtained to eliminate crossing customer septic systems and drain fields, or heavily wooded ROW.

Q. Please describe SHARP project, FRE 203, 35kV System Improvements Part 2.

A. As previously discussed, this project will improve reliability in an area that has very difficult access and consists of old wood structures with copper conductor. It will continue from Part 1, which is to commence in 2023, to replace the remaining two miles of three-phase overhead with three-phase underground.

Q. Please describe SHARP project, FRY 2733 Shag/Charlie Lakes UG Part 3.

A. From 2018 – 2020, Gwinn 653 was the 4th worst feeder in UPPCO. Part 3 continues work in the Shag Lakes areas establishing loops for redundancy and will also balance the load off the CR557 reclosers. This project will replace aged overhead conductor with approximately 8,000 of 1/0 URD on Shag Lake Road and establish new normal open points to create loops around the lakes. In addition, this project will allow for load balancing and provide an alternated feed to improve system flexibility for outage restoration. This project benefits 222 customers.

Q. Please describe SHARP project, GWN 657 Bass/Johnson Lakes Reliability Part 1.

A. From 2018 – 2021, Gwinn 657 became the 2nd worst feeder in UPPCO's service territory. Off-road overhead lines take the shortest path between lakes through heavily wooded areas. The 71 customers in this area are year-round residents, and areas of jack-pines create an increased risk of forest fire due to tree contacts. In winter months, service restoration times are increased due to the need for tracked equipment. This project will install 5,200ft of 1/0 underground in road ROW, replacing 1,800ft of #6 copper through a heavily wooded area, and establish a loop to facilitate quicker restoration times.

Q. Please describe SHARP project, PLK 401 Reliability Part 2, Squaw Lake.

A. Over the 5-year period of 2013-2017, Perch Lake circuit 401 was the worst rated feeder in UPPCO and was ranked the #1 worst feeder again over the years 2020-21 with a SAIDI of 33 minutes - experiencing a total of 141 outages over the past 2 years. The 39 customers served by the tap that feeds Squaw Lake have experienced 11 outages over the past 2 years, including two outages on the taps feeding Squaw Lake associated with the overhead line. Rerouting the line from overhead to underground, and placing it along the road, will eliminate the tree and weather-related outages and allow for easier access and quicker restoration when an outage does occur. The existing underground cable is also aged cable, so it will be replaced, as well. This project will replace approximately 1.25 miles of aged overhead facilities and install underground around Squaw Lake.

Q. Please describe SHARP project, M38 747 Copper replacement on M38 Part 3.

A. In 2022, Part 1 of this major project began converting two-phase copper overhead wire along M38 to three-phase underground cable. Part 2, described earlier, continued the underground conversion. Part 3 of this project will continue this undergrounding, which will improve reliability to an area of the system that has a SAIDI of 3.27 over the past 3 years. This project will install approximately 12,000ft of three-phase 4/0 cable, eight 3-phase junction boxes, 4 fuse pads, and 15 padmount transformers.

Q. Please describe SHARP project, HEN 1017 Chassell Painesdale Tie Reconductor.

A. A tie between HEN 1017-ATL 895 was created in 2018. However, the facilities on HEN 1017 limit the capacity of this tie. Additionally, many of the existing facilities were installed in the 1970s and are nearing the end of useful life and do not provide much overhead clearance over the many roads and driveways underneath these facilities. Reconductoring the facilities will improve the capacity of this line and create better clearance in this area. This project will rebuild approximately 21,000 ft of overhead facilities with 336 ACSR on relocated poles. This project benefits about 3,500 customers,

Q. Please describe SHARP project, LIN 3063 Establish 2-ph Tie Around Sunset Lake.

A. This project will improve reliability for 125 customers by closing a gap and establishing a loop around Sunset Lake in Iron River. The project will rebuild approximately 7,500ft in two sections of existing 1-phase to 2-phase overhead conductor and install 3,000ft of 2-phase conductor on the north side of the lake.

Q. Please describe SHARP project, ONN 863 Establish UG tie on M64 to Silver City.

A. The 446 customers in Ontonagon and 21 customers in Silver City along M64 are served by radial overhead lines that end 3,000ft apart. In 2017, the phasing at White Pine substation changed, which allows for a tie to be established between these two radial fed lines. Also, 5,000ft of the existing Silver City line has poor access. This will be brought out to the right of way to allow for better patrolling and quicker restoration times. By creating a tie and facilitating better access to the lines, reliability to the 467 customers in this area will be improved. From 2013-2017, these customers have experience 14 outages. Creating an underground loop and facilitating better access to these facilities will also reduce outage frequency and duration. This project will install approximately

9,000ft of 1/0 underground cable and remove approximately 5,300ft of overhead facilities.

Q. Please describe SHARP project, ATL 895 Relocate to Highway from Fountain Rd to Painesdale.

A. From 2013-2017, ATL 895 has the 5th highest SAIFI and 10th highest SAIDI in the UPPCO's service territory. Issues on the mainline have been a big contributor to these poor reliability numbers, resulting in 13 outages over the 5-year period, with an average duration of 1 hour and 55 minutes per outage. The reliability of this feeder, and specifically to the 462 customers served by this section of line, will be improved by relocating overhead facilities between South Range and Painesdale to the highway ROW for improved access. This project will relocate approximately 12,500ft of overhead facilities to the highway, install 336 ACSR on the relocated poles, and install a 3-phase regulator setting.

Q. Please describe SHARP project, LIN 3063 Lake Emily Iron River OH to UG conversion.

A. At Lake Emily in Iron River, 3,700ft of existing overhead facilities go through a swamp and are very difficult to access. This project will convert approximately 3,700ft of overhead to underground and replace transformers around Lake Emily.

These facilities serve 45 customers and include 14 poles that are nearing end of life. This project will convert the facilities from overhead to underground and bring them alongside the highway, where they will be more accessible.

Q. Please describe SHARP project, M38 749 Mansfeldt Rd Rebuild.

A. This project will install approximately 15,500ft of single phase 1/0 cable, four 1-phase junction boxes, 2 fuse pads, and 20 pad mount transformers, and will remove the existing overhead copper conductors and associated poles.

M38 749 had the #5 worst SAIDI in 2020 and #10 worst SAIDI and #9 worst SAIFI in 2021. The 57 customers in this area experienced the most outages over the past 3 years were in the Mansfeldt Road area. The existing facilities are old copper wire, which experienced 7 outages over the past 3 years. Rebuilding these facilities to underground will improve feeder performance and customer experience.

Q. Please describe SHARP project, System Hardening, OH TO UG Conversion, and Copper Replacement

A. This project is to capture miscellaneous projects that will arise over the course of the year as a result of storm activity, equipment failures, inspections, or in conjunction with requested customer work where reliability improvement can be realized. This project may consist of several relatively small capital investments or a couple larger scale projects. It allows for flexibility in creating additional customer value when a synergistic situation or condition presents itself.

Q. Please describe SHARP project, UG Unforeseen Replacement for End-of-Life Cable Failures.

A. This project is a placeholder for underground cable replacements due to failure. As discussed previously in my testimony, this project allows for flexibility over the course of a year to react to cable failures that inevitably occur with older cable. UPPCO has proactively replaced sections of old cable based on the number of failures over a period of time, but this project allows a reactive means to replace poor performing sections if warranted.

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 retail electric rates for	)	**Case No. U-21286**
the generation and distribution of	)	
electricity and other relief.	)	
	)	

DIRECT TESTIMONY OF

ADRIEN M. MCKENZIE

FOR

UPPER PENINSULA POWER COMPANY

September 8, 2022

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GLOSSARY

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)
MDPSC	Maryland Public Service Commission
Moody's	Moody's Investors Service
MW	megawatts
NASDAQ	The Nasdaq Stock Market LLC
PCE	Personal Consumption Expenditure Price Index
RCA	Regulatory Commission of Alaska
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
VIX	Chicago Board Options Exchange Volatility Index
Zacks	Zacks Investment Research, Inc.

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. Adrien M. McKenzie, 3907 Red River, Austin, Texas, 78751.

Q2. IN WHAT CAPACITY ARE YOU EMPLOYED?

A2. I am President of 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 AMM-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 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. HOW IS YOUR TESTIMONY ORGANIZED?

A6. After summarizing my findings and conclusions, I briefly review UPPCO's operations and finances. I then explain the development of the proxy group of electric utilities used as the basis for my quantitative analyses, including 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, the ECAPM, an equity risk premium approach based on allowed equity returns, and reference to expected earned rates of return for utilities, which are all methods that are commonly relied on in regulatory proceedings.

Finally, based on the cost of equity estimates indicated by my analyses described above, I conclude that the 10.8% ROE requested by UPPCO is fair and reasonable. This determination takes into account the specific risks for the Company's utility operations in Michigan and its requirements for financial strength. Further, consistent with the fact that utilities must compete for capital with firms outside their own industry, I corroborate the results of my utility quantitative analyses by applying the DCF model to a group of low-risk non-utility firms.

II. RETURN ON EQUITY FOR UPPCO

Q7. WHAT IS THE PURPOSE OF THIS SECTION?

A7. This section presents an overview of the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital under reasonable terms and summarizes the findings supporting my conclusion that the 10.8% ROE requested for

UPPCO's electric utility operations is a conservative estimate of investors' required rate of return for the Company.

A. Importance of Financial Strength

Q8. WHAT IS THE ROLE OF THE ROE IN SETTING A UTILITY'S RATES?

A8. The ROE is the cost of attracting and retaining common equity investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. Moreover, a just and reasonable ROE is integral in meeting sound regulatory economics and the standards set forth by the U.S. Supreme Court. 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.[1]

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

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[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).

> 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.[2]

In summary, the U.S. Supreme Court's findings in *Hope* and *Bluefield* 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 U.S. Supreme Court's requirements can only be met if the utility has a reasonable opportunity to actually earn its allowed ROE.

While the *Hope* and *Bluefield* decisions did not establish a particular method to be followed in fixing rates (or in determining the allowed ROE),[3] 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 comparable risk investments. Coupled with modern financial theory, which has led to the development of formal risk-return models (*e.g*., DCF, CAPM, and ECAPM), practical application of the *Bluefield* and *Hope* standards involves the independent, case-by-case consideration of capital market data in order to evaluate an ROE that will produce a balanced and fair end result for investors and customers.

Q9. THROUGHOUT YOUR TESTIMONY YOU REFER REPEATEDLY TO THE CONCEPTS OF "FINANCIAL STRENGTH," "FINANCIAL INTEGRITY,"

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[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

[3] *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.")

AND "FINANCIAL FLEXIBILITY." WOULD YOU BRIEFLY DESCRIBE WHAT YOU MEAN BY THESE TERMS?

A9. 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.

Q10. WHAT PART DOES REGULATION PLAY IN ENSURING THAT UPPCO HAS ACCESS TO CAPITAL UNDER REASONABLE TERMS AND ON A SUSTAINABLE BASIS?

A10. 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."[4] 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."[5] 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.[6]

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.

Q11. DO CUSTOMERS BENEFIT BY ENHANCING THE UTILITY'S FINANCIAL FLEXIBILITY?

A11. Yes. Providing an ROE that is sufficient to maintain the Company'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. Customers enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure safe and reliable service.

B. Recommended ROE

Q12. PLEASE SUMMARIZE THE RESULTS OF THE QUANTITATIVE ANALYSES THAT FORMED THE BASIS FOR YOUR CONCLUSIONS.

A12. In estimating a fair ROE for UPPCO, my analyses focused on a proxy group of eighteen publicly traded electric utilities. As discussed in my testimony:

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[4] Moody's Investors Service, *Regulation Will Keep Cash Flow Stable As Major Tax Break Ends*, Industry Outlook (Feb. 19, 2014).

[5] S&P Global Ratings, Assessing U.S. Investors-Owned Utility Regulatory Environments, RatingsExpress (Aug. 10, 2016).

[6] Value Line Investment Survey, *Water Utility Industry* (Jan. 13, 2017) at p. 1780.

- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied the DCF, CAPM, ECAPM, and risk premium methods to estimate a just and reasonable ROE, as well as referencing the expected earnings approach.
- 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 9.7% to 11.2% range.
- This conclusion is supported by average DCF estimates for a low-risk group of firms in the competitive sector of the economy, which ranged from 10.1% to 10.5%.[7]

Q13. ARE THE RESULTS OF YOUR ANALYSES DIRECTLY APPLICABLE TO UPPCO?

A13. 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 in the range of approximately 160 to 300 basis points to reflect the additional risks of UPPCO relative to the much larger electric utilities in the proxy group.

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[7] 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.

- As reflected in the testimony of Company witness Haehnel, UPPCO is requesting a fair ROE of 10.8%, which represents a conservative ROE for the Company.

Q14. WHAT OTHER FACTORS SHOULD BE CONSIDERED IN EVALUATING A FAIR ROE FOR THE COMPANY?

A14. 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. In addition, due to broad-based expectations for higher bond yields, current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

Q15. WHAT IS YOUR CONCLUSION AS TO THE REASONABLENESS OF THE COMPANY'S CAPITAL STRUCTURE?

A15. Based on my evaluation, I concluded that UPPCO's capital structure, consisting of approximately 10.8% common equity financing, represents a reasonable basis on which to establish the Company's return.

III. FUNDAMENTAL ANALYSES

Q16. WHAT IS THE PURPOSE OF THIS SECTION?

A16. As a foundation for my opinions and subsequent quantitative analyses, this section briefly reviews the operations and finances of UPPCO and examines conditions impacting todays' capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a fair ROE.

A. UPPCO Energy

Q17. BRIEFLY DESCRIBE UPPCO AND ITS MICHIGAN UTILITY OPERATIONS.

A17. UPPCO's regulated utility operations encompass the electric generation and distribution functions. Originally formed in 1947, UPPCO provides service to approximately 53,000 retail electric customers consisting of residential, commercial, industrial, and government entities, with industrial customers accounting for a plurality of the Company's sales. 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 two 49-year-old combustion turbines.

During 2021, UPPCO's total kilowatt hour sales distribution consisted of 35.0% residential, 18.4% commercial, 45.7% industrial, and 1.8% governmental and sales for resale.[8] 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. Its 2021 peak load of 163 MW occurred on December 1.[9] UPPCO's energy supply mix consists primarily of hydro (11.1%) and purchased energy (88.9%) sources.[10] UPPCO's total 2021 operating revenues were approximately $114.1 million and total assets at year-end 2021 were $410.5 million.[11]

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[8] UPPCO 2021 FERC Form 1 at 300-301. In 2021, UPPCO's total electric sales revenue consisted of 54.1% residential, 22.3% commercial, 21.1% industrial, 2.5% governmental and sales for resale.

[9] *Id.* at 401b.

[10] *Id.* at 401a.

[11] *Id.* at 114 and 111.

Q18. WHERE DOES UPPCO OBTAIN THE CAPITAL USED TO FINANCE ITS INVESTMENT IN UTILITY PLANT?

A18. 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, 2021, Axium Infrastructure had more than $6.0 billion in assets under management and $1.4 billion in co-investments.

Q19. DOES UPPCO ANTICIPATE THE NEED FOR CAPITAL GOING FORWARD?

A19. 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. Outlook for Capital Costs

Q20. PLEASE SUMMARIZE CURRENT ECONOMIC CONDITIONS.

A20. U.S. real GDP contracted 3.4% during 2020, but with the easing of lockdowns accompanying the COVID-19 vaccine rollout, the economic outlook improved significantly in 2021, with GDP growing at a pace of 5.7%. More recently, regional increases in COVID-19 cases, expiration of government assistance payments, and declines in wholesale trade led GDP to decrease at an annual rate of 1.6% and 0.9% in the first two quarters of 2022.[12] Meanwhile, indicators of employment remained stable, with the national unemployment rate in May 2022 remaining at 3.6%.[13]

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[12] https://www.bea.gov/news/2022/gross-domestic-product-second-quarter-2022-advance-estimate (last visited Aug. 6, 2022).

[13] https://www.bls.gov/charts/employment-situation/civilian-unemployment-rate.htm (last visited Jun. 21, 2022).

The underlying risk and unease associated with successive waves of the COVID-19 pandemic and related supply chain disruptions have been overshadowed by Russia's full-scale invasion of Ukraine on February 24, 2022. The dramatic increase in geopolitical risks has also been accompanied by heightened economic uncertainties as a wide-ranging sanctions regime seeks to isolate the Russian economy. As Fed Chair Powell concluded, "The financial and economic implications for the global economy and the U.S. Economy are highly uncertain."[14]

Stimulative monetary and fiscal policies, coupled with economic ramifications stemming from the conflict in Ukraine, have led to increasing concern that inflation may remain significantly above the 2% longer-run benchmark cited by the Federal Reserve. The U.S. inflation rate as measured by the CPI reached 9.1% in June 2022, its highest level since November 1981.[15] As illustrated in Figure AMM-1, below, inflation has now exceeded 5% for thirteen straight months. The so-called "core" price index, which excludes more volatile energy and food costs, rose at an annual rate of 5.9% in June 2022.

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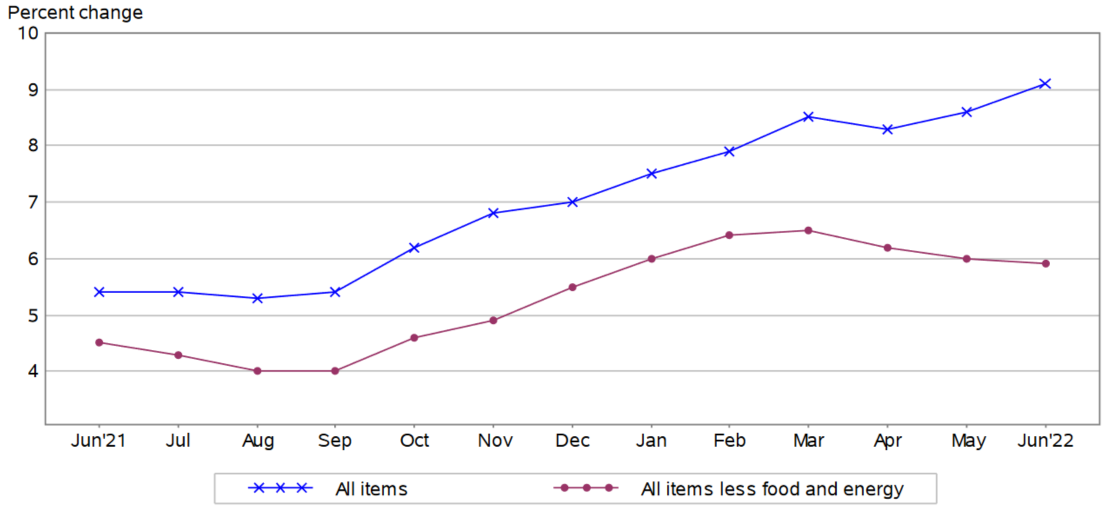
[14] Federal Reserve, *Transcript of Chair Powell's Press Conference* (Mar. 16, 2021), https://www.federalreserve.gov/monetarypolicy/fomcpresconf20220316.htm.

[15] https://www.bls.gov/news.release/pdf/cpi.pdf (last visited Aug. 6, 2022).

FIGURE AMM-1
TREND IN CONSUMER PRICE INDEX



Similarly, PCE inflation rose 6.8% in June 2022, or 4.8% after excluding more volatile food and energy cost.[16]

The Social Security Administration announced that beneficiaries would receive a cost-of-living adjustment of 5.9% for 2022, up from 1.3% a year earlier.[17] Meanwhile, the June 2022 *Survey of Consumer Expectations* conducted by the New York Fed reported a median point prediction for year-ahead inflation of 6.8% and an expected three-year inflation rate of 3.6%.[18] After abandoning the word "transitory" for describing the nature of the current high inflation rate,[19] Fed Chair Jerome Powell recently noted that:

> Inflation remains well above our longer-run goal of 2 percent. Over the 12 months ending in May, total PCE prices rose 6.3 percent; excluding the volatile food and energy categories, core PCE prices rose 4.7 percent.

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[16] https://www.bea.gov/news/2022/personal-income-and-outlays-june-2022 (last visited Aug. 6, 2022).

[17] Social Security Administration, Fact Sheet: 2022 Social Security Changes, https://www.ssa.gov/news/press/factsheets/colafacts2022.pdf.

[18] Federal Reserve Bank of New York, https://www.newyorkfed.org/microeconomics/sce#/inflexp-2 (last visited Aug. 6, 2022).

[19] https://www.reuters.com/article/usa-fed-instant/feds-powell-floats-dropping-transitory-label-for-inflation-idUSKBN2IF1S0.

> In June, the 12-month change in the Consumer Price Index came in above expectations at 9.1 percent, and the change in the core CPI was 5.9 percent. Notwithstanding the recent slowdown in overall economic activity, aggregate demand appears to remain strong, supply constraints have been larger and longer lasting than anticipated, and price pressures are evident across a broad range of goods and services. Although prices for some commodities have turned down recently, the earlier surge in prices of crude oil and other commodities that resulted from Russia's war on Ukraine has boosted prices for gasoline and food, creating additional upward pressure on inflation.[20]

As Value Line concluded, "Inflation clearly is worrisome."[21]

Q21. HOW HAVE COMMON EQUITY MARKETS BEEN IMPACTED BY THESE EVENTS?

A21. The threats posed by the coronavirus pandemic and military conflict in Ukraine have led to extreme volatility in the capital markets as investors have been forced to dramatically revise their risk perceptions and return requirements in the face of the severe disruptions to commerce and the world economy. Despite the actions of the world's central banks to ease market strains and bolster the economy, global equity markets have experienced precipitous declines as investors come to grips with the related exposures. S&P noted that the conflict "could have profound effects on macroeconomic prospects and credit conditions around the world,"[22] concluding that:

> The implications of the Russia-Ukraine conflict could come in the form of energy supply disruptions or price shocks, sustained inflationary pressures, a drag on economic growth or policy missteps by central banks, a migrant crisis in Eastern Europe, additional cyber attacks between Russia and its perceived adversaries, risk-repricing that drives up borrowing costs or limits funding access, and profit erosion for certain sectors.[23]

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[20] Federal Reserve, *Transcript of Chair Powell's Press Conference* (Jul. 7, 2022), https://www.federalreserve.gov/monetarypolicy/fomcpresconf20220727.htm.

[21] The Value Line Investment Survey, *Selection and Opinion* (Dec. 3, 2021).

[22] S&P Global Ratings, Russia-Ukraine Military Conflict: Key takeaways From Out Articles, Comments (Mar. 8, 2022).

[23] *Id.*

As Fed Chair Powell concluded, "The financial and economic implications for the global economy and the U.S. Economy are highly uncertain."[24]

The greater uncertainty faced by equity investors is confirmed by reference to the VIX,[25] which has trended sharply higher in 2022. Similarly, the Merrill Lynch Option Volatility Estimate, or "MOVE" index, which is a market-based measure of uncertainty about interest rates and is often referred to as the "investor fear gauge," is also elevated. During June 2022, the MOVE index fluctuated in the range of approximately 97 to 145, which is over 90% higher than it was at the same time in 2021.[26] This ongoing volatility in capital markets is evidence of the greater risks now faced by investors.

Q22. HAVE UTILITIES AND THEIR INVESTORS ALSO FACED HEIGHTENED LEVELS OF UNCERTAINTY?

A22. Yes. Concerns over weakening credit quality prompted S&P to revise its outlook for the regulated utility industry from "stable" to "negative."[27] As S&P explained:

> Even before the current downturn and COVID-19, a confluence of factors, including the adverse impacts of tax reform, historically high capital spending, and associated increased debt, resulted in little cushion in ratings for unexpected operating challenges.[28]

While recognizing that regulatory protections have helped to mitigate the worst of the coronavirus pandemic, S&P concluded that credit quality in the U.S. utility industry

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[24] Federal Reserve, *Transcript of Chair Powell's Press Conference* (Mar. 16, 2021), https://www.federalreserve.gov/monetarypolicy/fomcpresconf20220316.htm.

[25] The VIX is one of the most widely recognized measures of expectations of near-term volatility and market sentiment referenced by the investment community.

[26] https://www.google.com/finance/quote/MOVE:INDEXNYSEGIS?sa=X&ved=2ahUKEwiWvr7E-uH0AhVcl2oFHQLTAzsQ3ecFegQIBxAc&window=MAX (last visited Aug. 6, 2022).

[27] S&P Global Ratings, COVID-19: The Outlook For North American Regulated Utilities Turns Negative, RatingsDirect (April 2, 2020).

[28] S&P Global Ratings, North American Regulated Utilities Face Tough Financial Policy Tradeoffs To Avoid Ratings Pressure Amid The COVID-19 Pandemic, RatingsDirect (May 11, 2020).

weakened during 2020 and 2021, in part due to regulatory lag attributable to COVID-19.[29]

Meanwhile, rising inflation expectations also pose a challenge for utilities, with S&P recently noting that "the threat of inflation comes at a time when credit metrics are already under pressure relative to downside ratings thresholds."[30] S&P recently affirmed its negative outlook for investor-owned utilities, noting that "risk will continue to pressure the credit quality of the industry in 2022."[31] As S&P elaborated:

> Recently, several new credit risks have emerged, including inflation, higher interest rates, and rising commodity prices. Persistent pressure from any of these risks would likely lead to a further weakening of the industry's credit quality in 2022.[32]

Q23. DO CHANGES IN UTILITY COMPANY BETA VALUES SINCE THE PANDEMIC BEGAN CORROBORATE AN INCREASE IN INDUSTRY RISK?

A23. Yes. As I explain later, beta is used by the investment community as an important guide to investors' risk perceptions. As shown in Table AMM-4 subsequently, the average beta for the proxy group of utilities I rely on in this case for estimating the Company's ROE ("Electric Group"), is 0.90.[33] Prior to the pandemic, the average beta for the same group of companies was 0.57.[34]

The significant shift in pre- and post-pandemic beta values for the Electric Group is further exemplified in Figure AMM-2 below. As illustrated there, the Electric Group's

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[29] S&P Global Ratings, Report: North American Regulated Utilities' Credit Quality Begins The Year On A Downward Path, RatingsDirect (Apr. 7, 2021); S&P Global Ratings, For The First Time Ever, The Median Investor-Owned Utility Ratings Falls To The 'BBB' Category, RatingsDirect (Jan. 20, 2022).

[30] S&P Global Ratings, Will Rising Inflation Threaten North American Investor-Owned Regulated Utilities' Credit Quality? (Jul. 20, 2021).

[31] S&P Global Ratings, For The First Time Ever, The Median Investor-Owned Utility Ratings Falls To The 'BBB' Category, RatingsDirect (Jan. 20, 2022).

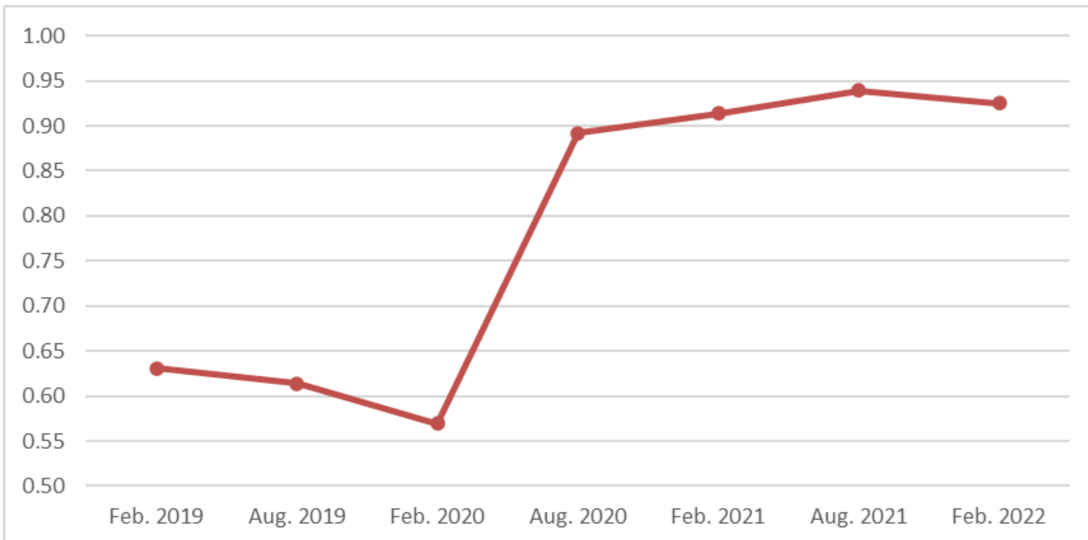
[32] *Id*.

[33] As indicated on Exhibit AMM-7, this is based on data as of June 24, 2022.

[34] The Value Line Investment Survey, *Summary & Index* (Feb. 14, 2020).

average beta value increased significantly with the beginning of the pandemic in March 2020, continued to increase during 2021, and has remained elevated in 2022. This dramatic increase in a primary gauge of investors' risk perceptions is further proof of the rise in the risk of utility common stocks.

FIGURE AMM-2
ELECTRIC GROUP BETA VALUES



Q24. HAVE INCREASED RISKS AND HIGHER INFLATION RESULTED IN HIGHER CAPITAL COSTS?

A24. 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. The table below compares the average yields on Treasury securities and Baa-rated public utility bonds during 2021 with those required in May 2022.

TABLE AMM-1
BOND YIELD TRENDS

Series	June 2022	2021	Change (bps)
10-Year Treasury Bonds	3.14%	1.44%	170
30-Year Treasury Bonds	3.25%	2.05%	120
Baa Utility Bonds	5.22%	3.35%	187

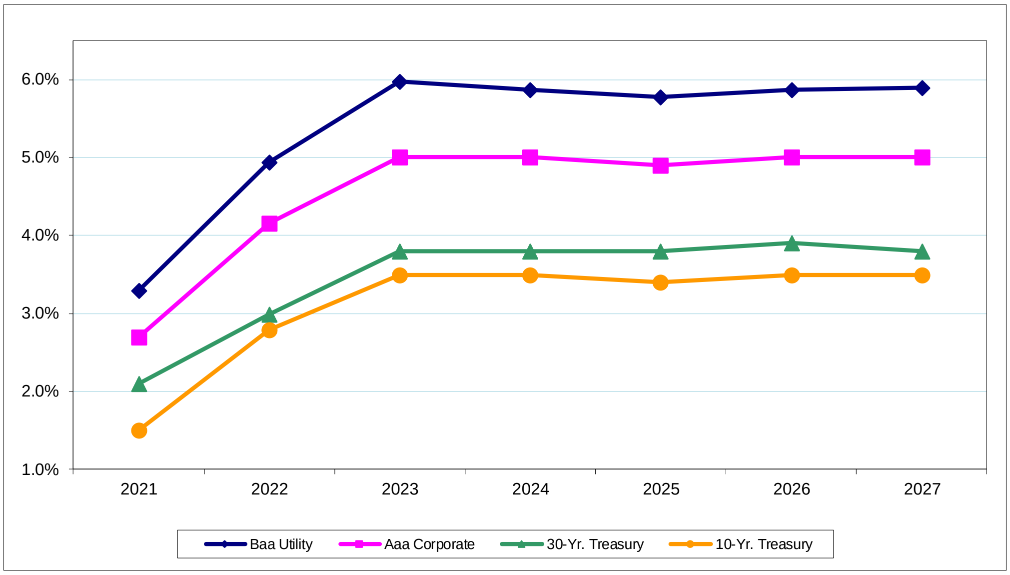
Source: https://fred.stlouisfed.org/series/GS30;
https://fred.stlouisfed.org/series/GS10; Moody's Credit Trends.

As shown above, trends in bond yields since 2021 document a substantial increase in the returns on long-term capital demanded by investors. 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 more than 180 basis points above 2021 levels.

Q25. ARE BOND YIELDS EXPECTED TO REMAIN ELEVATED OVER THE NEXT FEW YEARS?

A25. Yes. As illustrated in Figure AMM-3 below, economic forecasters anticipate a sustained increase in bond yields over the near-term.

FIGURE AMM-3
INTEREST RATE TRENDS



	2021	2022	2023	2024	2025	2026	2027	Change (bps) 2021-27
(a) 10-Yr. Treasury	1.5%	2.8%	3.5%	3.5%	3.4%	3.5%	3.5%	200
(a) 30-Yr. Treasury	2.1%	3.0%	3.8%	3.8%	3.8%	3.9%	3.8%	170
(a) Aaa Corporate	2.7%	4.2%	5.0%	5.0%	4.9%	5.0%	5.0%	230
(b) Baa Utility	3.3%	4.9%	6.0%	5.9%	5.8%	5.9%	5.9%	260

(a) Wolters Kluwer, Blue Chip Financial Forecasts (Jun. 1, 2022).
(b) Based on projected yields on Baa corporate bonds (Wolters Kluwer, Blue Chip Financial Forecasts (Jun. 1, 2022)), adjusted for six-month average yield spreads at Jun. 2022 (Moody's Investors Service).

Q26. ARE EXPECTATIONS OF HIGHER BOND YIELDS AND EXPOSURE TO INFLATION CONSISTENT WITH RECENT FEDERAL RESERVE ACTIONS AND THE VIEWS OF THE FOMC?[35]

A26. Yes. The FOMC responded to concerns over accelerating inflation by raising the benchmark range for the federal funds rate by 0.25% in March 2022, 0.50% in May 2022, 0.75% in June, and a further 0.75% at its policy meeting on July 26-27, 2022. Chair Powell noted that:

[35] The FOMC is a committee composed of twelve members that serves as the monetary policymaking body of the Federal Reserve System.

> From the standpoint of our Congressional mandate to promote maximum employment and price stability, the current picture is plain to see: The labor market is extremely tight, and inflation is much too high. Against this backdrop, today the FOMC raised its policy interest rate by 3/4 percentage point and anticipates that ongoing increases in the target range for the federal funds rate will be appropriate.[36]

The Federal Reserve also began a significant draw-down of its balance sheet holdings beginning in June 2022,[37] and Fed Chair Powell surmised that this process could be the equivalent of another one quarter percent rate hike over the course of a year.[38]

In conjunction with the June 14-15, 2022 policy meeting, the FOMC submitted updated projections about where short-term interest rates are headed. The results are the dot plot—a visual representation of where members think interest rates will trend over the short, medium, and longer run. As shown in Figure AMM-4 below, the most recent dot plot indicates that all of the FOMC participants expect its benchmark interest rate to be dramatically higher than current levels by the end of 2022,[39] with the median of the federal funds target range rising to 3.375% , versus 2.375% currently.

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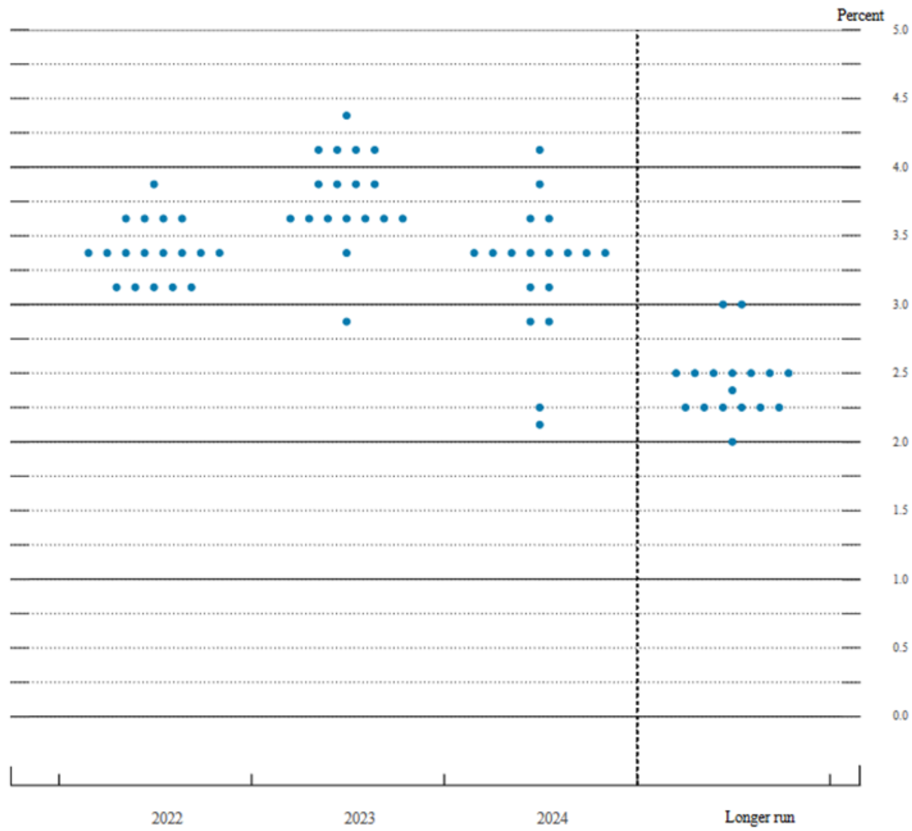
[36] https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20220727.pdf.

[37] Federal Reserve, *Plans for Reducing the Size of the Federal Reserve's Balance Sheet,* Press Release (May 4, 2022), https://www.federalreserve.gov/newsevents/pressreleases/monetary20220504b.htm

[38] Federal Reserve, *Transcript of Chair Powell's Press Conference* (May 4, 2022), https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20220504.pdf.

[39] Summary of Economic Projections (Jun. 15, 2022). https://www.federalreserve.gov/monetarypolicy/files/fomcprojtabl20220316.pdf.

FIGURE AMM-4
FEDERAL RESERVE DOT PLOT



Q27. WHAT IMPLICATIONS DO THESE FORECASTS HAVE IN EVALUATING A FAIR ROE FOR UPPCO?

A27. These expectations for higher interest rates suggest that long-term capital costs—including the cost of equity—will increase significantly over the intermediate term. As a result, cost of equity estimates based on current data are likely to understate the return that will be required by investors over the period when the rates established in this proceeding will be in effect.

Q28. WOULD IT BE REASONABLE TO DISREGARD THE IMPLICATIONS OF CURRENT CAPITAL MARKET CONDITIONS IN ESTABLISHING A FAIR ROE FOR UPPCO?

A28. No. They 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 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 necessary capital.

IV. DETERMINATION OF THE PROXY GROUP

Q29. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A29. My objective is to evaluate and recommend a just and reasonable ROE for UPPCO. Much of my work is predicated on a comparison of the Company with the electric utility industry, and more specifically to a proxy group of publicly traded electric utilities. This section explains the basis for the proxy group I used to estimate the cost of equity, examines alternative objective indicators of investment risk for these firms, and compare the investment risks of UPPCO with my reference group.

Q30. HOW DO YOU IMPLEMENT QUANTITATIVE METHODS TO ESTIMATE THE COST OF COMMON EQUITY FOR UPPCO?

A30. 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 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.

Q31. HOW DO YOU IDENTIFY THE PROXY GROUP OF UTILITIES RELIED ON FOR YOUR ANALYSES?

A31. 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."

Q32. WHAT OTHER PUBLICLY TRADED UTILITY IS RELEVANT FOR YOUR ANALYSES?

A32. In addition to the utilities meeting the criteria outlined 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.[40] 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 95% of consolidated net income.[41] Emera Inc.'s Florida and New Mexico utility operations account for 64% of consolidated net income.[42] Emera Inc. has been assigned credit ratings of Baa3 by Moody's and BBB by S&P, which fall within the criteria discussed above. Thus, investors would regard Emera Inc. as a comparable investment alternative that is relevant to an evaluation of the required rate of return for UPPCO.

These criteria result in the proxy group of eighteen companies listed on page 1 of Exhibit AMM-3, which I refer to as the "Electric Group."

A. UPPCO's Relative Risks

Q33. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A33. 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 Electric Group with those that investors would associate with UPPCO

[40] In addition to Emera, Inc., I also considered Algonquin Power & Utilities Company. While this company would be regarded as a comparable utility investment opportunity by investors, it did not meet my required screening criteria due to a major acquisition, which is ongoing.

[41] Emera, Inc., *Investors Presentation* (March 2022). https://s25.q4cdn.com/978989322/files/doc_presentations/2022/03/March-2022-Marketing-Presentation_FINAL.pdf (last visited Mar. 23, 2022).

[42] *Id.*

and evaluates the incremental return necessary to compensate for the Company's greater relative risks.

i. Operating Risks

Q34. HOW DO THE CHARACTERISTICS OF UPPCO'S SERVICE TERRITORY DIFFERENTIATE THE COMPANY FROM THE LARGER UTILITIES IN THE PROXY GROUP?

A34. 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. It serves approximately 53,000 electric retail customers in 10 of the Upper Peninsula of Michigan's 15 counties, or about 12 customers per square mile. UPPCO's service territory of 4,460 square miles covers primarily rural countryside. Industries served by the Company include forest products, tourism, and manufacturing.[43] The potential for uncertain and extreme weather increases the complexities of operating in such an environment.

Q35. HOW DO WEATHER-RELATED RISKS AFFECT UPPCO'S FINANCIAL POSITION?

A35. 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

[43] https://business.keweenaw.org/list/member/upper-peninsula-power-company-houghton-396 (last visited July 8, 2022).

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 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.

Q36. DO EXTREME WEATHER EVENTS EXPERIENCED IN 2021 ALSO HIGHLIGHT THE IMPORTANCE OF MAINTAINING UPPCO'S FINANCIAL INTEGRITY?

A36. 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.

Q37. DOES THE COMPANY'S POWER SUPPLY MIX ADD TO THE COMPANY'S RISK PROFILE?

A37. Yes. The Company's primary source of energy supply is through hydro generation and purchases in the wholesale market. In 2021, hydro sources supplied 11.1% of the

Company's total energy needs and purchases provided 88.9%.[44] Both of these sources entail added risk. While hydropower confers advantages in terms of fuel 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.[45]

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.

Q38. HOW DOES CLIMATE CHANGE IMPACT INVESTORS' ASSESSMENT OF UPPCO'S RISK EXPOSURE?

A38. 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

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[44] UPPCO 2021 FERC Form 1 at 401a.

[45] Standard & Poor's Corporation, "Pacific Northwest Hydrology And Its Impact On Investor-Owned Utilities' Credit Quality," *RatingsDirect* (Jan. 28, 2008).

adaptation," and concluded that water stress is "a serious threat."[46] 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:

> 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.[47]

Q39. WHAT OTHER FACTORS SPECIFIC TO UPPCO'S SERVICE AREA WARRANT CONSIDERATION?

A39. UPPCO's service area is characterized by a high concentration of sales to industrial customers relative to the companies in the Electric Group. Approximately 45.5% of the Company's total energy sales are to industrial customers,[48] versus an average of 24.4% for the eighteen firms in the Electric 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.

Q40. CAN YOU GIVE SPECIFIC EXAMPLES OF THE RISKS ASSOCIATED WITH UPPCO'S VOLATILE INDUSTRIAL CUSTOMER BASE?

A40. 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

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[46] S&P Global Ratings, *Keeping The Lights On: U.S. Utilities' Exposure To Physical Climate Risks*, RatingsDirect (Sep. 16, 2021).

[47] *Id.*

[48] UPPCO 2021 FERC Form 1 at 304.

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.

Further, in 2016 Cleveland-Cliffs, Inc. announced the closing of the Empire Mine in Ishpeming, Michigan. The Empire Mine, located in UPPCO's service area, was one of the last iron ore mines operating in the state. 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

Q41. WOULD INVESTORS ALSO CONSIDER THE IMPLICATIONS OF REGULATORY MECHANISMS IN EVALUATING UPPCO'S RELATIVE RISKS?

A41. 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.[49]

As shown on Exhibit AMM-3, and reflective of this trend, the companies in the Electric 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, bad debt expenses, certain taxes and fees, post-retirement employee benefit costs and transmission-related charges.

Q42. DO THE REGULATORY MECHANISMS APPROVED FOR THE COMPANY HAVE IMPLICATIONS FOR INVESTORS' EVALUATION OF RELATIVE RISKS?

A42. 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 Electric Group, the Company lacks cost tracking mechanisms to address ongoing capital investment outside of a traditional

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[49] S&P Global Market Intelligence, *Adjustment Clause: A state-by-state overview*, RRA Regulatory Focus (Jul. 18, 2022).

rate case. Nor does UPPCO benefit from a normalization adjustment or decoupling mechanism to insulate utility margins from weather fluctuations or declining usage.

iii. Implications of Firm Size

Q43. HOW DOES A SMALL ELECTRIC UTILITY SUCH AS UPPCO COMPARE TO THE LARGE, PUBLICLY TRADED FIRMS IN YOUR PROXY GROUP?

A43. There is enormous disparity in size between UPPCO and the major participants in the electric utility industry. Consider the eighteen utilities making up the Electric Group, for example, which dwarf UPPCO by any measure. For example, where the Electric Group had average annual revenues in 2021 of approximately $8.6 billion and total capital of $28.7 billion, UPPCO had revenues of $115.3 million and total capital of $351.1 million.[50] Similarly, compared with UPPCO's 53,000 customers, on average the firms in the Electric Group supply utility services to 3.8 million customers.

Q44. WHAT DIFFERENCE DOES THIS DISTINCTION IN SIZE MAKE?

A44. 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.

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 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

[50] UPPCO 2021 Financial Statements.

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.

Q45. IS THERE EMPIRICAL EVIDENCE IN THE FINANCIAL LITERATURE THAT A COMPANY'S SIZE AFFECTS ITS RELATIVE RISKS?

A45. 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.[51] Similarly, a classic University of Kansas study demonstrated that large firms are assigned higher bond ratings than small firms with similar characteristics,[52] and there is ample empirical evidence that investors in smaller firms realize higher rates of return than in larger firms.[53] 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.[54]

Q46. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT REQUIRED TO ACCOUNT FOR THIS SIZE PREMIUM?

A46. One estimate of the size premium is available from Kroll,[55] which now reports the widely-recognized Ibbotson Associates data based on historical returns for "Low-Cap"

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[51] Eugene F. Fama and Kenneth R. French, "The Cross-Section of Expected Stock Returns", *The Journal of Finance* (June 1992), p. 429.

[52] George E. Pinches, J. Clay Singleton, and Ali Jahankhani, "Fixed Coverage as a Determinant of Electric Utility Bond Ratings", *Financial Management* (Summer 1978).

[53] See for example Rolf W. Banz, "The Relationship Between Return and Market Value of Common Stocks", *Journal of Financial Economics* (September 1981) at 16.

[54] 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.

[55] 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.

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.

TABLE AMM-2

CRSP Decile Size Premium as of December 31, 2021

Decile	Market Capitalization of Smallest Company (in millions)		Market Capitalization of Largest Company (in millions)	Size Premium (Return in Excess of CAPM)
Mid-Cap 3-5	$ 3,281.009	-	$ 16,738.364	0.66%
Low-Cap 6-8	629.118	-	3,276.553	1.23%
Micro-Cap 9-10	10.588	-	627.803	3.04%
Breakdown of Deciles 1-10				
1-Largest	$36,160.584	-	$2,324,390.219	-0.17%
2	16,759.390	-	36,099.221	0.44%
3	8,216.356	-	16,738.364	0.57%
4	5,019.883	-	8,212.638	0.56%
5	3,281.009	-	5,003.747	0.91%
6	2,170.315	-	3,276.553	1.20%
7	1,306.402	-	2,164.524	1.36%
8	629.118	-	1,306.038	1.28%
9	290.002	-	627.803	2.11%
10- Smallest	10.588	-	289.007	4.85%
Breakdown of CRSP 10th Decile				
10a	$ 190.487	-	$ 289.007	3.38%
10w	251.715	-	289.007	2.37%
10x	190.487	-	251.505	4.62%
10b	$ 10.588	-	$ 190.440	7.91%
10y	127.920	-	190.440	6.37%
10z	10.588	-	127.729	11.25%

Source: *Kroll Cost of Capital Navigator, www.costofcapital.kroll.com.*

As shown above, the individual firms in the Low-Cap group have market capitalizations at or below about $3.3 billion but greater than $629 million, with the market capitalization of Micro-Cap stocks falling between approximately $11 million and $628 million. These smaller companies have historically earned higher rates of return than the large companies comprising the S&P 500. For the 1926 to 2021 period, Kroll reported a size premium in excess of the return implied by the CAPM of 123 basis points for the Low-Cap sector, and 304 basis points for Micro-Cap companies.

Q47. HOW ELSE MIGHT THE SIZE PREMIUM BE ESTIMATED FOR UPPCO?

A47. The additional return attributable to the significant distinction in size between UPPCO and the Electric 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 $193.2 million by the average market-to-book ratio for the Electric Group of 1.92 times. This implies a market capitalization for UPPCO of $371.0 million. As shown in Table AMM-2, this corresponds to the 9th decile of the publicly-traded firms, which had market capitalizations ranging from $290.0 to $627.8 million and a size premium of 2.11%.

Meanwhile, the average market capitalization for the firms in the Electric Group is $25.3 billion, which corresponds to the 2nd decile. Subtracting the size premium associated with the Electric Group of 44 basis points from the 211 basis-point premium for a firm in the 9th decile results in an implied size adjustment of 167 basis points to reflect the additional risks of UPPCO relative to the much larger electric utilities in the proxy group.

Q48. 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.

A48. While faced with added risks related to its small size, potentially volatile power supply mix, economically vulnerable service area, and lack of regulatory mechanisms, 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.

B. Capital Structure

Q49. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS RETURN ON EQUITY?

A49. 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.

Q50. WHAT COMMON EQUITY RATIO IS IMPLICIT IN UPPCO'S STRUCTURE?

A50. As supported in the testimony of Company witness Haehnel, UPPCO is requesting that its rates be set using its projected test year capital structure ending June 30, 2024, with a common equity ratio of approximately 53.96%.

Q51. HOW DOES THIS COMPARE TO THE AVERAGE CAPITALIZATION MAINTAINED BY THE ELECTRIC GROUP?

A51. As shown on page 1 of Exhibit AMM-4, for the firms in the Electric Group, common equity ratios at December 31, 2021 ranged from 31.0% to 59.8% and averaged 43.7%, with Value Line expecting an average common equity ratio of 45.7% for its three-to-five year forecast horizon.

Q52. WHAT CAPITALIZATION RATIOS ARE MAINTAINED BY UTILITY OPERATING COMPANIES?

A52. Pages 2 and 3 of Exhibit AMM-4 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 Electric Group used to estimate the cost of equity. As shown there, common equity ratios for these utilities range from 39.7% to 60.5% and average 50.6%.

Q53. DO ONGOING ECONOMIC AND CAPITAL MARKET UNCERTAINTIES ALSO INFLUENCE THE APPROPRIATE CAPITAL STRUCTURE FOR UPPCO?

A53. 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.[56]

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[56] Moody's Investors Service, *FAQ on credit implications of the coronavirus outbreak*, Sector Comment (Mar. 26, 2020).

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 market conditions. Moreover, small utilities face greater uncertainties than do their larger counterparts, which also supports a conservative financial posture.

Q54. WHAT DOES THIS EVIDENCE SUGGEST WITH RESPECT TO THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A54. Based on my evaluation, I concluded 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 Electric 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.

V. CAPITAL MARKET ESTIMATES AND ANALYSES

Q55. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A55. This section presents capital market estimates of the cost of equity. First, I discuss the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe various quantitative analyses conducted to estimate the cost of common equity for the proxy group of comparable risk utilities.

A. Economic Standards

Q56. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THE COST OF EQUITY CONCEPT?

A56. 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 compete 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.

Q57. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE OPERATES IN THE CAPITAL MARKETS?

A57. 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.

Q58. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A58. 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 – required rates of return cannot be observed. Yet there is every reason to believe that investors demonstrate risk aversion in deciding whether to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q59. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A59. 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.

Q60. WHAT ARE THE CHALLENGES IN DETERMINING A JUST AND REASONABLE ROE FOR A REGULATED ENTERPRISE?

A60. 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, 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.

Q61. IS IT CUSTOMARY TO CONSIDER THE RESULTS OF MULTIPLE APPROACHES WHEN EVALUATING A JUST AND REASONABLE ROE?

A61. 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."[57] 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

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

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.[58]

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."[59] 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. 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.[60]

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 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

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

[59] *Id*.

[60] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 429.

> 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.[61]

More recently, FERC recognized the potential for any application of the DCF model to produce unreliable results.[62]

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.

Q62. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE ROE FOR A UTILITY?

A62. Although the ROE is unobservable, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is not readily observable, the ROE for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

B. Discounted Cash Flow Analyses

Q63. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF COMMON EQUITY?

A63. 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

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[61] *Ind. Michigan Power Co.*, Cause No. 38728, 116 PUR4th, 1, 17-18 (IURC 8/24/1990).

[62] *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234 at P 41 (2014).

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:[63]

$$P_0 = \frac{D_1}{k_e - g}$$

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:

$$k_e = \frac{D_1}{P_0} + g$$

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.

Q64. WHAT STEPS ARE REQUIRED TO APPLY THE CONSTANT GROWTH DCF MODEL?

A64. 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

[63] 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.

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.

Q65. HOW DO YOU DETERMINE THE DIVIDEND YIELDS FOR THE ELECTRIC GROUP?

A65. 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 Electric Group are presented on Exhibit AMM-5. As shown on the first page of this exhibit, dividend yields for the firms in the Electric Group range from 2.4% to 4.7% and average 3.6%.

Q66. WHAT IS THE NEXT STEP IN APPLYING THE CONSTANT GROWTH DCF MODEL?

A66. 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.

Q67. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A67. 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.

Q68. DO THE GROWTH RATE PROJECTIONS OF SECURITY ANALYSTS CONSIDER HISTORICAL TRENDS?

A68. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q69. DID PROFESSOR MYRON J. GORDON, A PIONEER OF THE CONSTANT GROWTH DCF APPROACH, RECOGNIZE THE PIVOTAL ROLE THAT EARNINGS PLAY IN FORMING INVESTORS' EXPECTATIONS?

A69. Yes. Dr. Gordon specifically recognized that "it is the growth that investors expect that should be used" in applying the DCF model and he concluded, "A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[64]

Q70. ARE ANALYSTS' ASSESSMENTS OF GROWTH RATES APPROPRIATE FOR ESTIMATING INVESTORS' REQUIRED RETURN USING THE DCF MODEL?

A70. Yes. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

The highly competitive market for investment guidance supports a finding that analysts' estimates are relied on by investors. If financial analysts' forecasts do not add value to investors' decision-making, then it is irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial

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[64] Myron J. Gordon, *The Cost of Capital to a Public Utility*, MSU Public Utilities Studies (1974) at 89.

media and in investment advisory publications (*e.g.*, Value Line) implies that investors use them as a basis for their expectations.

While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic—is irrelevant if investors share analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. <u>The accuracy of these forecasts in the sense of whether they turn out to be correct is not an issue here, as long as they reflect widely held expectations</u>.[65]

Q71. HAVE OTHER REGULATORS ALSO RECOGNIZED THAT ANALYSTS' GROWTH RATE ESTIMATES ARE AN IMPORTANT AND MEANINGFUL GUIDE TO INVESTORS' EXPECTATIONS?

A71. Yes. The Kentucky Public Service Commission has indicated its preference for relying on analysts' projections in establishing investors' expectations:

> KU's argument concerning the appropriateness of using investors' expectations in performing a DCF analysis is more persuasive than the AG's argument that analysts' projections should be rejected in favor of historical results. The Commission agrees that analysts' projections of growth will be relatively more compelling in forming investors' forward-looking expectations than relying on historical performance . . .[66]

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[65] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 298 (emphasis added).

[66] *Kentucky Utilities Co.*, Case No. 2009-00548 (Ky PSC Jul. 30, 2010) at 30-31.

Similarly, The Public Utility Regulatory Authority of Connecticut has also noted that "there is not growth in DPS without growth in EPS," and concluded that securities analysts' growth projections have a greater influence over investors' expectations and stock prices.[67] In addition, the RCA has previously determined that analysts' EPS growth rates provide a superior basis on which to estimate investors' expectations:

> We also find persuasive the testimony . . . that projected EPS returns are more indicative of investor expectations of dividend growth than historical growth data because persons making the forecasts already consider the historical numbers in their analyses.[68]

The RCA has concluded that arguments against exclusive reliance on analysts' EPS growth rates to apply the DCF model "are not convincing."[69]

Q72. WHAT SOURCES OF SECURITY ANALYSTS' EPS GROWTH RATES DO YOU RELY ON IN YOUR DCF ANALYSIS?

A72. I rely on EPS growth projections for each of the firms in the Electric Group reported by Value Line, IBES,[70] and Zacks. These growth rates are displayed on page 2 of Exhibit AMM-5.

Q73. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS OFTEN ESTIMATED WHEN APPLYING THE CONSTANT GROWTH DCF MODEL?

A73. 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

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[67] *Decision*, Docket No. 13-02-20 (Sept. 24, 2013).

[68] Regulatory Commission of Alaska, U-07-76(8) at 65, n. 258.

[69] Regulatory Commission of Alaska, U-08-157(10) at 36.

[70] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Refinitiv.

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 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 AMM-5, with the underlying details being presented on Exhibit AMM-6.

The sustainable growth rate analysis shown in Exhibit AMM-6 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 AMM-6, is solely a means of converting Value Line's end-of-period values to an average return over the year.[71]

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[71] *See,* Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 305-306.

Q74. ARE THERE SIGNIFICANT SHORTCOMINGS ASSOCIATED WITH THE "BR+SV" GROWTH RATE?

A74. 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 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.[72] 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.

Q75. WHAT COST OF COMMON EQUITY ESTIMATES ARE IMPLIED FOR THE ELECTRIC GROUP USING THE DCF MODEL?

A75. 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 AMM-5.

Q76. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE ILLOGICAL ESTIMATES?

A76. Yes. It is essential that cost of equity estimates resulting from quantitative methods pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

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[72] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 307.

Q77. HAVE OTHER REGULATORS EMPLOYED SUCH TESTS?

A77. Yes. FERC has noted that adjustments are justified where applications of the DCF approach and other methods produce illogical results. FERC evaluates low-end DCF results against observable yields on long-term public utility debt and eliminates estimates that do not sufficiently exceed this threshold,[73] while also excluding estimates that are "irrationally or anomalously high."[74] Similarly, the Staff of the MDPSC recently elected to eliminate DCF values below 6.5%, observing that returns "below that level would be too close to [the utility's] cost of debt to be attractive to an equity investor."[75]

Q78. DO YOU EXCLUDE ANY ESTIMATES AT THE LOW OR HIGH END OF THE RANGE OF RESULTS?

A78. Yes. As highlighted on page 3 of Exhibit AMM-5, I eliminate eleven low-end DCF estimates ranging from 1.6% to 6.9%. Based on my professional experience and 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 AMM-5, I eliminate two high-end DCF estimates of 17.4% and 14.5%. The upper end of the remaining DCF results for the Electric Group is set by a cost of equity estimate of 13.1%. While a 13.1% cost of equity estimate may exceed the majority of the remaining values, low-end DCF estimates in the 7.1% to 7.8% range are assuredly far below investors' required rate of return. Taken

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[73] *See, e.g., Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 55 (2010).

[74] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 171 FERC ¶ 61,154 at P 152 (2020).

[75] Maryland Public Service Commission, Case No. 9670, *Direct Testimony and Exhibits of Drew M. McAuliffe* (Dec. 2, 2021) at 15-16.

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.

Q79. WHAT ROE ESTIMATES ARE IMPLIED BY YOUR DCF RESULTS FOR THE ELECTRIC GROUP?

A79. As shown on page 3 of Exhibit AMM-5 and summarized in Table AMM-3, below, after eliminating illogical values, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE AMM-3
DCF RESULTS – ELECTRIC GROUP

Growth Rate	Average	Midpoint
Value Line	8.7%	9.0%
IBES	10.0%	10.5%
Zacks	9.4%	10.4%
br + sv	8.6%	8.6%

Q80. WHAT DO THE INTEREST RATE PROJECTIONS DISCUSSED EARLIER IN YOUR TESTIMONY IMPLY WITH RESPECT THESE DCF ESTIMATES?

A80. As documented in Figure AMM-3, interest rates on Baa utility bonds are projected to be approximately 1.0% higher over the 2023-2027 timeframe than they are currently. As will be discussed in more detail later in my testimony, the cost of equity moves in the same direction as interest rates, but by approximately one-half as much.[76] This suggests that a 1.0% increase in Baa utility bond yields would imply an increase of about 50 basis points over current DCF estimates to account for higher capital costs when rates will be in effect.

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[76] *See,* Exhibit AMM-8, page 6; Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 129 (noting that, "The gist of the empirical research on this subject is that the cost of equity has changed only half as much as interest rates have changed in the past.").

C. Capital Asset Pricing Model

Q81. PLEASE DESCRIBE THE CAPM.

A81. 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.

Q82. WHY IS THE CAPM APPROACH A RELEVANT COMPONENT WHEN EVALUATING THE COST OF EQUITY FOR UPPCO?

A82. The CAPM approach (which also forms the foundation of the ECAPM) 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 (and ECAPM) provides important insight into investors' required rate of return for utility stocks, including the Company.

Q83. HOW DID YOU APPLY THE CAPM TO ESTIMATE THE ROE?

A83. 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 AMM-7. 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, Zacks, and Value Line, 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 10.5%. Combining this average growth rate with a year-ahead dividend yield of 2.0% results in a current cost of common equity estimate for the market as a whole (R_m) of 12.5%. Subtracting a 3.3% risk-free rate based on the average yield on 30-year Treasury bonds for June 2022 produced a market equity risk premium of 9.2%.

Q84. IN PREVIOUS TESTIMONY YOU HAVE CUSTOMARILY RELIED ON A SIX-MONTH AVERAGE YIELD ON TREASURY BONDS AS THE RISK-FREE RATE. WHY ARE YOU NOW REFERENCING THE JUNE 2022 AVERAGE?

A84. Coupled with the Federal Reserve's recent decision to adopt tighter monetary policies, increased concerns over rising inflation and geopolitical risks has led to a significant upward shift in bond yields. As a result, six-month average data does not reflect investors' current expectations and requirements. Accordingly, I relied on June 2022 yield averages to better reflect present economic realities. This is particularly important in light of even higher interest rates projected over the intermediate term.

Q85. WHAT WAS 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 relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings.

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.[77]

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.[78] Accordingly, my CAPM analyses also incorporates an adjustment to recognize the

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[77] Morningstar, *Ibbotson SBBI 2015 Classic Yearbook*, at pp. 99, 108.

[78] 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*.

impact of size distinctions, as measured by the market capitalization for the firms in the Electric 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 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."

A publication available from the National Association of Certified Valuators and Analysts documented the relevance of the size adjustment in applying the CAPM:

> [A] beta-adjusted size premium is also an indication of the relative market performance of small-cap versus large-cap stocks, but is typically used for a very specific purpose: as a "size" adjustment within the context of the capital asset pricing model (CAPM) when developing cost of equity capital estimates. A size adjustment is typically applied to the CAPM to make up for the fact that the betas of smaller companies do not fully explain their observed returns. Because the CAPM already includes a beta input in its textbook specification, the size premium is then "beta adjusted" to remove the portion of realized excess return that is attributable to beta, thereby isolating the size effect's contribution to

> realized excess return and avoiding double counting the impact of each factor.
>
> * * *
>
> Another way of saying this is that within the context of the CAPM, the betas of small-cap companies do not fully account for (or explain) their actual returns. Because the amount of this difference (what actually happened versus what CAPM predicted) varies with "size" (in this case, as measured by market capitalization) we call it a "size premium". [79]

Similarly, *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."[80]

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,"[81] and includes the size adjustment in the CAPM under its ROE methodology for electric utilities and natural gas and oil pipelines.[82] More recently, FERC affirmed its practice of including a size adjustment, concluding that "the 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."[83]

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[79] *Using a Non-Beta-Adjusted Size Premium in the Context of the CAPM Will Likely Overstate Risk and Understate Value* (Jan. 30, 2019), available at http://quickreadbuzz.com/2019/01/30/business-valuation-grabowski-harringtonsing-a-non-beta-adjusted-size-premium/.

[80] Roger A. Morin, *New Regulatory Finance* 187 (Pub. Utils. Reports, Inc., 2006).

[81] *Coakley v. Bangor-Hydro-Elec. Co.*, Opinion No. 531-B, 150 FERC ¶ 61,165 at P 117 (2015).

[82] 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).

[83] 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).

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 Electric 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 ELECTRIC GROUP USING THE CAPM APPROACH?

A90. As shown on page 1 of Exhibit AMM-7, after adjusting for the impact of firm size, the CAPM approach implies an average ROE for the Electric Group of 12.1%.

Q91. DO YOU ALSO APPLY THE CAPM USING FORECASTED BOND YIELDS?

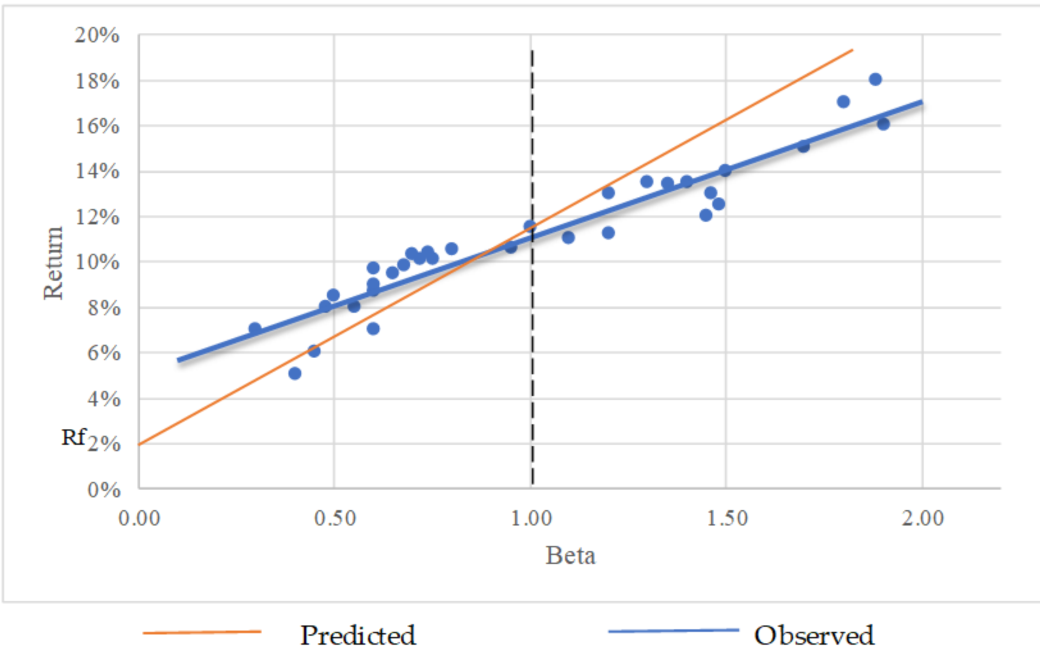
A91. Yes. As discussed earlier, widely recognized economic forecasting services indicate that interest rates are expected to increase over the near-term. Accordingly, in addition to the use of current bond yields, I apply the CAPM based on the projected yields on 30-year Treasury bonds published by Blue Chip. As shown on page 2 of Exhibit AMM-7, incorporating an average forecasted Treasury bond yield of 3.8% for 2023-2027 implies an average cost of equity estimate of 12.1% for the Electric Group.

D. Empirical Capital Asset Pricing Model

Q92. HOW DOES THE ECAPM APPROACH DIFFER FROM TRADITIONAL APPLICATIONS OF THE CAPM?

A92. Empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta, with low-beta stocks tending to have higher returns and high-beta stocks tending to have lower risk returns than predicted by the CAPM. This is illustrated graphically in Figure AMM-5:

FIGURE AMM-5
CAPM – PREDICTED VS. OBSERVED RETURNS



Because the betas of utility stocks, including those in the proxy group, are generally less than 1.0, this implies that cost of equity estimates based on the traditional CAPM would understate the cost of equity. This empirical finding is widely reported in the finance literature, as summarized in *New Regulatory Finance*:

> As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical relationships.[84]

[84] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports (2006) at 189.

As discussed in *New Regulatory Finance*,[85] based on a review of the empirical evidence, the expected return on a security is related to its risk by the ECAPM, which is represented by the following formula:

$$R_j = R_f + 0.25(R_m - R_f) + 0.75[\beta_j(R_m - R_f)]$$

Like the CAPM formula presented earlier, the ECAPM represents a stock's required return as a function of the risk-free rate (R_f), plus a risk premium. In the formula above, this risk premium is composed of two parts: (1) the market risk premium ($R_m - R_f$) weighted by a factor of 25%, and (2) a company-specific risk premium based on the stock's relative volatility [$\beta_j(R_m - R_f)$] weighted by 75%. This ECAPM equation, and its associated weighting factors, recognizes the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research, and corrects for the understated returns that would otherwise be produced for low beta stocks.

Q93. IS THE USE OF THE ECAPM CONSISTENT WITH THE USE OF VALUE LINE BETAS?

A93. Yes. Value Line beta values are adjusted for the observed tendency of beta to converge toward the mean value of 1.00 over time.[86] The purpose of this adjustment is to refine beta values determined using historical data to better match forward-looking estimates of beta, which are the relevant parameter in applying the CAPM or ECAPM models. Meanwhile, the ECAPM does not involve any adjustment to beta whatsoever. Rather, it represents a formal recognition of findings in the financial literature that the observed risk-return tradeoff illustrated in Figure AMM-5 is flatter than predicted by the CAPM. In other words, even if a firm's beta value were estimated with perfect precision, the

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[85] *Id.* at 190.

[86] *See, e.g.,* Marshall E. Blume, *Betas and Their Regression Tendencies*, Journal of Finance (Jun. 1975), pp. 785-795.

CAPM would still understate the return for low-beta stocks and overstate the return for high-beta stocks. The ECAPM and the use of adjusted betas represent two separate and distinct issues in estimating returns.

Q94. HAVE OTHER REGULATORS RELIED ON THE ECAPM?

A94. Yes. Staff witnesses for the MDPSC have relied on this approach in prior testimony, noting that "the ECAPM model adjusts for the tendency of the CAPM model to underestimate returns for low Beta stocks," and concluding that "the ECAPM gives a more realistic measure of the ROE than the CAPM model does."[87] The staff of the Colorado Public Utilities Commission has recognized that, "The ECAPM is an empirical method that attempts to enhance the CAPM analysis by flattening the risk-return relationship,"[88] and relied on the exact same standard ECAPM equation presented above.[89]

The New York Department of Public Service also routinely incorporates the results of the ECAPM approach, which it refers to as the "zero-beta CAPM."[90] Similarly, the Montana Public Service Commission has endorsed the ECAPM method, stating that:

> [T]he evidence in this proceeding has convinced the Commission that the Empirical Capital Asset Pricing Model ("ECAPM") should be the primary method for estimating the [utility's] cost of equity."[91]

The RCA has also relied on the ECAPM approach, concluding:

> Tesoro averaged the results it obtained from CAPM and ECAPM while at the same time providing empirical testimony that the ECAPM results are more accurate then [sic] traditional CAPM results. The reasonable

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[87] *Direct Testimony and Exhibits of Julie McKenna*, Wyoming PSC Case No. 9299 (Oct. 12, 2012) at 9.

[88] Proceeding No. 13AL-0067G, *Answer Testimony and Attachments of Scott England* (July 31, 2013) at 47.

[89] *Id.* at 48.

[90] *See, e.g.*., New York Department of Public Service, Cases 19-E-0065 19-G-0066, *Prepared Fully Redacted Testimony of Staff Finance Panel* (May 2019) at 94-95.

[91] *Mont. Pub. Serv. Comm'n*, Order No. 7575c at P114 (Sept. 26, 2018).

> investor would be aware of these empirical results. Therefore, we adjust Tesoro's recommendation to reflect only the ECAPM result.[92]

The Wyoming Office of Consumer Advocate, an independent division of the Wyoming Public Service Commission, has also relied on this ECAPM formula in estimating the cost of equity for a regulated utility,[93] as has a witness for the Office of Arkansas Attorney General.[94]

Q95. WHAT COST OF EQUITY IS INDICATED BY THE ECAPM?

A95. My application of the ECAPM is based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connections with the CAPM. As shown on page 1 of Exhibit AMM-8, applying the forward-looking ECAPM based on the average yield on 30-year Treasury bonds for June 2022 results in an average cost of equity estimate of 12.3% for the Electric Group.

As shown on page 2 of Exhibit AMM-8, incorporating a forecasted Treasury bond yield for 2023-2027 implies an average cost of equity for the Electric Group of 12.4%.

E. Utility Risk Premium

Q96. BRIEFLY DESCRIBE THE RISK PREMIUM METHOD.

A96. 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

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[92] Regulatory Commission of Alaska, Order No. P-97-004(151) (Nov. 27, 2002) at 145.

[93] *Pre-Filed Direct Testimony of Anthony J. Ornelas*, Docket No. 30011-97-GR-17, (May 1, 2018) at 52-53.

[94] *Direct Testimony of Marlon F. Griffing, PH.D.*, Docket No. 17-071-U, (May 29, 2018) at 33-35.

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.

Q97. IS THE RISK PREMIUM APPROACH A WIDELY ACCEPTED METHOD FOR ESTIMATING THE COST OF EQUITY?

A97. 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.

Q98. HOW DID YOU IMPLEMENT THE RISK PREMIUM METHOD?

A98. 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.

Q99. IS IT CIRCULAR TO CONSIDER RISK PREMIUMS BASED ON AUTHORIZED RETURNS IN ASSESSING A JUST AND REASONABLE ROE FOR UPPCO?

A99. No. In establishing authorized returns, regulators typically consider the results of multiple market-based approaches and other indicators of capital costs. Because allowed risk premiums consider objective market data (*e.g.*, stock prices, dividends, beta, and interest rates), and are not based strictly on past actions of other regulators, this mitigates concerns over any potential for circularity.

Q100. HOW DID YOU CALCULATE THE EQUITY RISK PREMIUMS BASED ON ALLOWED RETURNS?

A100. 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 3 of Exhibit AMM-9, 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 2021.[95] As shown there, over this period these equity risk premiums for electric utilities average 3.87%, and the yields on public utility bonds average 7.89%.

Q101. IS THERE ANY CAPITAL MARKET RELATIONSHIP THAT MUST BE CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM METHOD?

A101. 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 periods. Given that equity risk premiums move inversely with interest rates, these lower

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[95] My analysis encompasses the entire period for which published data is available.

bond yields also imply an increase in the equity risk premium that investors require to accept the higher uncertainties associated with an investment in utility common stocks versus bonds. In other words, it is reasonable to assume that a higher required equity risk premium currently offsets the impact of current interest rates being lower than historical interest rates over the risk premium study period.

Q102. HAS THIS INVERSE RELATIONSHIP BEEN DOCUMENTED IN THE FINANCIAL RESEARCH?

A102. 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 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.[96]

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.[97] This relationship is illustrated in the figure on page 4 of Exhibit AMM-9.

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[96] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports (2006) at 128.

[97] *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. 8, 2022); *Martha Coakley et al.*, 147 FERC ¶ 61,234 at P 147 (2014).

Q103. WHAT ROE IS IMPLIED BY THE RISK PREMIUM METHOD USING SURVEYS OF ALLOWED RETURNS?

A103. Based on the regression output between the interest rates and equity risk premiums displayed on page 4 of Exhibit AMM-9, the equity risk premium for electric utilities increases by approximately 43 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit AMM-9 with an average yield on public utility bonds for June 2022 of 4.91%, this implies a current equity risk premium of 5.15% for electric utilities. Adding this equity risk premium to the average yield on Baa utility bonds for June 2022 implies a current ROE of 10.37%.

Q104. WHAT RISK PREMIUM COST OF EQUITY ESTIMATE IS PRODUCED AFTER INCORPORATING PROJECTED BOND YIELDS?

A104. As shown on page 2 of Exhibit AMM-9, incorporating an average projected yield for 2023-2027 and adjusting for changes in interest rates since the study period implies an equity risk premium of 4.85% for electric utilities, which is less than the current equity risk premium. This lower equity risk premium is consistent with the inverse relationship I described above. Adding this equity risk premium to the implied average yield on Baa utility bonds for 2023-2027 of 5.87% results in an implied cost of equity of 10.72%.

F. Expected Earnings Approach

Q105. WHAT OTHER ANALYSES DO YOU CONDUCT TO ESTIMATE THE ROE?

A105. I also evaluate the ROE using the expected earnings method. 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*.[98] 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.

Q106. WHAT ECONOMIC PREMISE UNDERLIES THE EXPECTED EARNINGS APPROACH?

A106. 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.

Q107. HOW IS THE EXPECTED EARNINGS APPROACH TYPICALLY IMPLEMENTED?

A107. 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

[98] *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).

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.

Q108. WHAT ROES ARE INDICATED FOR UPPCO BASED ON THE EXPECTED EARNINGS APPROACH?

A108. 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 AMM-10. 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.[99] Accordingly, these

[99] 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.

year-end values were converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit AMM-6. As shown on Exhibit AMM-10, Value Line's projections suggest an average ROE of 10.8% for the Electric Group.

VI. NON-UTILITY BENCHMARK

Q109. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A109. This section presents the results of my DCF analysis applied to a group of low-risk firms in the competitive sector, which I refer to as the "Non-Utility Group." This analysis was 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 just and reasonable ROEs for the Company's electric utility operations.

Q110. DO UTILITIES HAVE TO COMPETE WITH NON-REGULATED FIRMS FOR CAPITAL?

A110. 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.

Q111. IS IT CONSISTENT WITH THE *BLUEFIELD* AND *HOPE* CASES TO CONSIDER INVESTORS' REQUIRED ROE FOR NON-UTILITY COMPANIES?

A111. 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.[100]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Q112. DOES CONSIDERATION OF THE RESULTS FOR THE NON-UTILITY GROUP IMPROVE THE RELIABILITY OF DCF RESULTS?

A112. 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.

Q113. WHAT CRITERIA DO YOU APPLY TO DEVELOP THE NON-UTILITY GROUP?

A113. 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 less than 1.00; and
5) have investment grade credit ratings from Moody's and S&P.

[100] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 391 (1944).

Q114. HOW DO THE OVERALL RISKS OF THIS NON-UTILITY GROUP COMPARE WITH THE ELECTRIC GROUP?

A114. Table AMM-4 compares the Non-Utility Group with the Electric Group across the measures of investment risk discussed earlier.

TABLE AMM-4
COMPARISON OF RISK INDICATORS

			Value Line		
	S&P	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Non-Utility Group	A	A3	1	A+	0.79
Electric Group	BBB+	Baa2	2	B++	0.90

Apart from the assessment of default risk provided by credit ratings, other quality rankings published by investment advisory services also provide relative assessments of risk that are considered by investors in forming their expectations. Accordingly, my evaluation also included a comparison of three other objective measures of the investment risks associated with common stocks—Value Line's Safety Rank, Financial Strength Rating, and beta. Given that Value Line is perhaps the most widely available source of investment advisory information, its rankings provide useful guidance regarding the risk perceptions of investors.

The Safety Rank is Value Line's primary risk indicator and ranges from "1" (Safest) to "5" (Most Risky). This overall risk measure is intended to capture the total risk of a stock, which incorporates elements of stock price stability and financial strength. 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. Finally, as noted earlier, beta measures the volatility of a security's price relative to the market as a whole. Beta is the only relevant measure of investment risk under modern capital market theory and is cited widely in academia and in the investment industry as a guide to investors' risk perceptions.

As the table shows, a comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position, relative size, and exposure to company-specific factors, indicates that investors would likely conclude that the overall investment risks for the Electric Group are greater than those of the firms in the Non-Utility Group.

The companies that make up the Non-Utility Group, which are shown in Exhibit AMM-11, are representative of the pinnacle of corporate America. These firms, which include household names such as Coca-Cola, Kellogg, Procter & Gamble, and Walmart, have long corporate histories, well-established track records, and conservative risk profiles. Many of these companies pay dividends on a par with utilities, with the average dividend yield for the group at 2.2%. 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.

Q115. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY GROUP?

A115. 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 the Non-Utility Group are presented in Exhibit AMM-11. As summarized in Table AMM-5, after eliminating illogical values, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE AMM-5
DCF RESULTS – NON-UTILITY GROUP

Growth Rate	Average	Midpoint
Value Line	10.1%	10.5%
IBES	10.5%	10.7%
Zacks	10.3%	10.7%

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.

Q116. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A116. 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 retail electric rates for the generation and distribution of electricity and other relief.	))))))	**Case No. U-21286**

DIRECT TESTIMONY OF

KAY L. RYAN

FOR

UPPER PENINSULA POWER COMPANY

September 8, 2022

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 Plant Human Resources Manager. In December 2012 I left Leprino Foods and entered into employment with Potlatch as a Plant 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")?

A. No.

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

A. The purpose of my testimony is to present UPPCO's compensation structure and benefit plans for the projected test period beginning July 1, 2023 and ending June 30, 2024 ("projected test year").

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Confidential Exhibit A-64 (KLR-1) and Confidential Exhibit A-64 (KLR-2). Both of these exhibits were 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 qualified employees 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.

A substantial number of UPPCO employees are bargaining unit employees and are represented by the International Brotherhood of Electrical Workers, Local 510. The most recent Collective Bargaining Agreement ("CBA") took effect on April 13, 2018. The CBA negotiated competitive wages for the bargaining unit employees through April 15,

2023. The previous CBA negotiated competitive wages for the bargaining unit employees through April 12, 2018.

For the Administrative, Non-Bargaining Unit employees, the compensation structure was established to compete for and retain quality 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 and are reviewed at least annually to ensure our compensation programs will attract and retain a quality workforce to serve our customers.

Q. Since UPPCO's last rate case in 2019, Case No. U-20276, has the Company's compensation structure materially changed? Please explain.

A. No. However, the Company now offers a deferred compensation program intended to attract and retain, qualified employees 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. I explain this in further detail later in my testimony.

Q. Please explain what has changed as it relates to the attraction and retention of employees?

A. The market for hiring skilled, qualified, and experienced workers has changed considerably. There are not enough qualified individuals to fill open positions, most candidates are passive, and there is an increased competition for candidates, requiring employers to become even more creative with their total compensation and benefit strategies.

Q. How are increases in base pay determined?

A. For Bargaining Unit Employees, base pay increases annually by the amount negotiated in the CBA. Administrative, Non-Bargaining Unit employees will be offered the opportunity for an annual merit increase. Merit increases will be based on performance measures set by and then evaluated by the employees and their supervisor/manager. Performance measures will be based on business objectives that are determined each year. Administrative, Non-Bargaining Unit 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 Exhibit A-64 (KLR-1) [CONFIDENTIAL] for a copy of the policy.

Q. Does UPPCO's Compensation Plan include variable pay programs?

A. Yes, UPPCO's Compensation Plan also includes a variable pay program with two components: 1) Pay-At-Risk Pay based on meeting certain key safety and operational performance targets, and 2) Incentive Pay based on the financial performance of the Company.

Q. Which variable pay plans are included in the projected test year?

A. Consistent with UPPCO's treatment in Case No. U-20276, Pay-At-Risk Pay, which does not have a financial qualifier, is included in the projected test costs for the year ending June 30, 2024.

Q. Please explain UPPCO's Pay-At-Risk Pay?

A. UPPCO offers Administrative, Non-Bargaining Unit employees, additional performance-based compensation on an annual basis, for meeting specific safety and customer operations metrics. This is called Pay-At-Risk. This pay is based on achieving results that will have a direct impact on increased customer satisfaction, and improved reliability. UPPCO's Pay-at-Risk pay, is predicated on meeting safety and operational goals. Again, no financial qualifiers are utilized in determining Pay-at-Risk pay.

Q. How do Safety metrics benefit customers?

A. Safety metrics benefit UPPCO customers by 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 safety, customer safety, and employee safety become a daily part of what we do. The Pay-At-Risk Safety metrics encourage increased safety, which leads to more efficiency and lower costs, and ultimately is a direct benefit to customers.

Q. How do Operational metrics benefit customers?

A. Operational metrics benefit UPPCO 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 services provided to our customers.

Q. What is the projected test year value of the Pay-At-Risk target?

A. The value of UPPCO's Pay-At-Risk target for the projected test year is __________.

Q. Explain UPPCO's Incentive Pay?

A. UPPCO provides Incentive Pay to Administrative, Non-Bargaining Unit employees, including Executives, on an annual basis for meeting a financial goal of earnings (adjusted EBITDA). This Incentive Pay is based on achieving results that have a direct impact on managing the cost of service to customers and increasing operational efficiencies. UPPCO's Incentive Pay utilizes the EBIDTA metric as a qualifier.

Q. Does UPPCO offer any other incentive compensation programs not covered by the UPPCO Compensation Plan?

A. Yes, UPPCO offers a Deferred Compensation Plan. Please see Exhibit A-65 (KLR-2) [CONFIDENTIAL] for a copy of the policy.

Q. Explain the Deferred Compensation Plan.

A. UPPCO provides market-based Deferred Compensation to Senior Executives, on an annual basis for meeting environmental, safety and customer service metrics. This Deferred Compensation is based on achieving results that have a direct impact on managing the cost of service to customers and increasing operational efficiencies. The Deferred Compensation Pay does not utilize any financial metrics as a qualifier, but instead focuses on safety, environmental, reliability, and customer service, which provide a benefit to customers.

Q. What is the projected test year value of the Deferred Compensation Plan?

A. The value of UPPCO’s Deferred Compensation Plan target for the projected test year is ______________________ as represented in Confidential Exhibit A-24 (GRH-26) sponsored by Company Witness Haehnel.

EMPLOYEE BENEFIT PLANS

Q. Who is eligible for UPPCO’s benefit plans?

A. (1) Full-time, Regular, Active Administrative, Non-Bargaining Unit Employees and eligible dependents; (2) Full-time, Regular, Active Bargaining Unit Employees; and eligible dependents (3) Retirees who have met eligibility criteria and eligible dependents.

Q. What benefits does UPPCO offer to its Active Employees?

UPPCO offers Medical, Health Savings Account, Prescription, Medical Emergency Transport, Cash in Lieu of Benefits for employees waiving medical due to alternate group medical coverage, Dental, Vision, Flexible Spending Account, Life Insurance, Accidental Death & Dismemberment, Short Term Disability, Long Term Disability, Employee Assistance Program, COBRA, 401(k) Match, 401(k) Non-Elective Age + Service Contribution (only applicable to non-pension eligible employees hired 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, Child Life, Identity Theft Protection.

Q. Why does UPPCO offer these benefits?

A. Offering these benefits allows UPPCO to attract and retain a qualified and motivated workforce in a market that includes regulated and non-regulated energy companies as well as non-energy organizations. UPPCO has marketed the benefit plans for comparable offerings and either maintained existing benefits or reduced benefits to be more consistent with the market. As the market for human capital demands shift, UPPCO feels it is important to offer a benefit package that is competitive in the marketplace to attract and retain employees which reduces turnover and costs associated with turnover.

Q. Have the benefits and/or benefits programs materially changed since UPPCO's last rate case in 2019, Case No. U-20276?

A. No.

Q. Describe the Medical Benefits.

A. UPPCO offers two 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 an 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 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 UPPCO 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 Active Employees and their dependents?

A. No, UPPCO and employees share the cost of the premiums for medical and prescription coverage. Administrative, Non-Bargaining Unit Employees and Bargaining Unit Employees, pay a percentage of the premiums, in accordance with the CBA. Per the CBA, for 4.13.2018-4.15.2023, employees pay 20% of premiums. If premiums increase greater than 15% during the annual renewal period, the Company and Union agree to enter into negotiations regarding the selection of another plan.

Q. Describe the Dental Benefits.

A. The dental plan is separate from the medical plan and 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 Active Employees and their dependents?

A. No, UPPCO and employees share the cost of the premiums for dental coverage. Administrative, Non-Bargaining Unit Employees and Bargaining Unit Employees, pay a percentage of the premiums, in accordance with the CBA. Per the CBA, for 4.13.2018-4.15.2023, employees pay 40% of cost, with UPPCO paying 60% of cost.

Q. Describe the Vision Benefits.

A. The vision plan is separate from the medical plan and 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 the coverage that best fits their needs.

Q. Does UPPCO pay the entire cost of the premium for vision coverage for Active Employees and their dependents?

A. No, UPPCO and employees share the cost of the premiums for vision coverage. Administrative, Non-Bargaining Unit Employees and Bargaining Unit Employees pay a percentage of the premiums, in accordance with the CBA. Per the CBA, for 4.13.2018-4.15.2023, employees pay 50% of the cost of either plan, with UPPCO paying the remaining 50%.

Q. Describe the Flexible Spending Account Benefit.

A. The Flexible Spending Account ("FSA") benefit allows 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), Health Care FSA, or Dependent Care FSA that is 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, UPPCO pays an annual fee of $250 and a monthly fee of $4.90 per active participant.

Q. Describe the Identity Theft Protection Benefit.

A. The Identity Theft Protection benefit allows employees to purchase identity theft through payroll deduction. There are two levels of benefits to choose from, Pro and Pro Plus. Benefits are underwritten through Allstate Identity Protection.

Q. Is there a cost to UPPCO for providing this benefit?

A. There is no cost to UPPCO for providing this benefit.

Q. Describe the Life Insurance Benefit.

A. UPPCO offers Basic Life, Supplemental Life and Dependent Life insurance underwritten by Prudential Life Insurance Company. Employees receive company-sponsored life insurance benefits and have the option to purchase additional life insurance on themselves and their qualified dependents.

Q. What is UPPCO’s total monthly premium for Basic Life coverage?

A. The total monthly cost of Basic Life Insurance is $.23 per $1,000 of coverage. UPPCO pays 100% of the cost.

Q. What is the cost for Employee-Only Supplemental Life?

A. The rates employees pay for employee only supplemental life coverage is based on the amount of coverage they select and their age. There is no cost to UPPCO for providing this benefit.

Q. What is the cost for Spouse Supplemental Life?

A. The rates employees pay for spouse supplemental life coverage is based on the amount of coverage they select and their age. There is no cost to UPPCO for providing this benefit.

Q. What is the cost for Child(ren) Supplemental Life?

A. The rates the employee pays are based on the amount of coverage selected. 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. 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 result in the death or dismemberment of a covered person

Q. What is UPPCO's total monthly cost of Basic AD&D coverage?

A. The total monthly cost of Basic AD&D coverage is $.022 per $1,000 of coverage. UPPCO pays 100% of the cost.

Q. What is the cost for Supplemental AD&D?

A. The rates the employee pays are based on the amount of coverage selected. There is no cost to UPPCO for providing this benefit.

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. The benefit for Administrative, Non-Bargaining Unit Employees is 60% of weekly earnings, up to $2,000 weekly. Bargaining Unit Employees, receive a $500 weekly benefit in accordance with the CBA.

Q. Is there a cost to UPPCO for providing this benefit?

A. The cost to UPPCO for Short-Term Disability coverage is $.28 per $10 of benefit. UPPCO pays 100% of the cost.

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 of time, typically 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-Bargaining Unit Employees is 60% of monthly earnings, up to $15,000 monthly. Bargaining Unit

Employees, receive a 66 2/3% 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. The cost to UPPCO for Long-Term Disability coverage is $.518 per $100 of benefit. UPPCO pays 100% of the cost.

Q. Describe the Employee Assistance Program Benefit.

A. The Employee Assistance Program (“EAP”) program 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. The cost to UPPCO for providing the EAP program is $250 annually and $3.25 monthly per employee. UPPCO pays 100% of the cost.

Q. Describe the COBRA Benefit.

A. COBRA is the Consolidated Omnibus Budget Reconciliation Act and allows 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. The cost to UPPCO for providing third party COBRA administration coverage is approximately $215.00 per month.

Q. Describe the Matching 401(k) Savings Plan Benefit.

A. Key features of the 401(k) plan are:

Company Matching Contribution — For Bargaining Unit Employees hired prior to April 19, 2009, UPPCO matches 50% on the first 6.5% of base pay and overtime that employees contribute to the 401(k) plan. Employees are always 100% vested in the Company match.

Company Matching Contribution — For Administrative, Non-Bargaining Unit Employees and Bargaining Unit Employees hired on or after April 19, 2009, UPPCO matches dollar for dollar the first 5% of base pay and overtime that employees contribute to the 401(k) plan. The match occurs automatically, and employees are always 100% vested in the Company match.

Defined Contribution Discretionary Contributions — For Administrative, Non-Bargaining Unit Employees and Bargaining Unit Employees hired on or after April 19, 2009, UPPCO makes a discretionary 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: Sum of Participant's 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: age 0 -34 = 3%, 35 - 49 = 4%, 50 - 64 = 5%, 65 - 79 = 6%, and age 80 and above= 7% of total eligible compensation for all participants eligible for the allocation.

Q. Describe the Pension Benefit.

A. UPPCO offers a traditional pension benefit to eligible employees hired prior to April 19, 2009. The plan was closed to new entrants hired after April 19, 2009. For employees who are eligible for this pension plan, benefit accruals will continue to include years of service and earnings as defined in the plan.

Q. Describe the Wellness Program Benefit.

A. UPPCO offers a formal wellness program through Blue Cross Blue Shield of Michigan Health & Wellness to all employees of UPPCO and their spouses at no cost to the employee. The Wellness Program is designed to teach employees about how their own lifestyle, through an online health assessment questionnaire, may affect their overall health and encourage preventive care through completing an annual health exam to catch potential health concerns early, before becoming a major concern.

Q. Is there a cost to UPPCO for providing this benefit?

A. The cost for providing this benefit is in the form of the HSA contributions or payroll contributions received by the employee based on the activities the employee and spouse complete. 1. Complete the Online Health Assessment - $100 Wellness Credit 2. Complete a preventive visit and biometric screening with their physician - $200 Wellness Credit. Access to the Wellness Program through BCBSM is $30 per member (employee-spouse) per year. UPPCO only experiences costs for the health coaching or tobacco cessation as employees engage in the programs. For health coaching, the pricing is based on the health risk of the member - $100 for Low Risk, $200 for Medium Risk, $300 for

High Risk. For tobacco cessation, the fee is $315. These are one-time fees per engaged members.

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. The Tuition Reimbursement Program 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 any ineligible expenses, consistent with the 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.

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 the family, 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 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 of medical benefit.

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 all employees are New Year's Day, Good Friday, Memorial Day, July 4th, Labor Day, Thanksgiving and the Day After, Christmas Eve, and Christmas Day. Vacation time is offered to employees on a sliding scale based on years of service.

Q. What benefits does UPPCO offer to retirees?

A. Medical (Closed to new entrants per the CBA or Retiree Medical Care Credit Program), Prescription (Closed to new entrants per the CBA or Retiree Medical Care Credit Program), Dental (Closed to new entrants and only applicable to some retirees), Vision (Closed to new entrants per the CBA or Retiree Medical Care Credit Program), 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 health 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. Retirees over the age of 65 are offered Medicare Advantage with Prescription Drug Coverage ("MAPD") plan. There is one small segment of retirees, with an average age of

85, enrolled in a closed MAPD plan mirroring a Medigap plan. These 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 retirees have the option of electing three years of free coverage as part of their retirement package. There are a very limited number of individuals that retired from UPPCO when UPPCO 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 Bargaining Unit employees can also elect up to three years of free coverage upon retirement. Once the three-year free coverage period has ended, the retiree is responsible for 50% of their medical premiums. There is also one small segment of Administrative Employees who have attained age 45 and are able to accrue Retiree Medical Care Credits ("RMCC"). Employees are vested 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. Retirees may elect to use RMCC 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 is the same as that available to active Bargaining Unit and 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 Bargaining Unit and Administrative 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 available to retired Administrative Employees and retired or currently active Bargaining Unit Employees. It is a closed benefit. A closed segment of Administrative Employees and Bargaining Unit 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 of the plan is $6.48 per $1,000 of coverage.

Q. Is there anything else you would like to share regarding compensation or benefits?

A. Yes. The benefits provided under the previous ownership reflected economies of scale that are difficult to achieve in a smaller operation. UPPCO has continued to evolve its compensation and benefit programs to remain competitive for attraction and retention of employees, while continuing to implement cost-savings measures.

Additionally, wherever possible, UPPCO has contracted with benefit providers that are Michigan based companies. For example, the medical and wellness plans are provided by BCBSM (Michigan) and dental is provided by Delta Dental of Michigan. UPPCO has also partnered with a benefits broker, VAST. 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 & UPPCO partnered with Health Insurance Services ("HIS") to manage the retiree medical benefits. HIS is a Michigan based brokerage firm specializing in retiree medical benefits.

Q. Do you propose that UPPCO recover in the rates the costs of the UPPCO Compensation and Benefits Plans in their entirety?

A. Yes, the projected test year costs are represented by Company Witness Haehnel in Exhibit A-25 (GRH-27).

Q. Does this conclude your pre-filed direct testimony at this time?

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 retail electric rates for	)	**Case No. U-21286**
the generation and distribution of	)	
electricity and other relief.	)	
	)	

DIRECT TESTIMONY OF

ERIC W. STOCKING

FOR

UPPER PENINSULA POWER COMPANY

September 8, 2022

QUALIFICATIONS

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

A. My name is Eric W. Stocking. My business address is 1002 Harbor Hills Drive, Marquette, Michigan 49855. I am employed by Upper Peninsula Power Company ("UPPCO" or the "Company").

Q. Please provide your title and describe your job responsibilities.

A. My title is Manager of Rates & Power Supply, and my responsibilities encompass a wide variety of issues touching several aspects of UPPCO's business, including regulatory affairs, power supply and resource planning, cost of service analysis and rate design, sales and peak demand forecasting, and Renewable Portfolio Standard ("RPS") compliance planning and analysis.

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 took on the role of Economic Specialist in the Resource Adequacy and Retail Choice area 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

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 sponsored testimony in UPPCO's 2018 rate case and 2019 Integrated Resource Plan proceeding, among others. In November 2019, I assumed my current role as Manager of Rates & Power Supply.

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-20276 (General Rate Case), U-20350 (Integrated Resource Plan) ("IRP"), 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. The purpose of my testimony is provide direct support for the following areas of UPPCO's general rate application for the projected test year period encompassing July 1, 2023, through June 30, 2024 ("Projected Test Year").

1. Compliance with prior Commission Orders
2. U-20995 Regulatory Asset.
3. Low-Income Residential Tariff
4. Electric Heating Rebate Program
5. Electric Vehicle Charging Program Update
6. Projected Test Year Cost of Service Study
7. State Reliability Mechanism: Capacity Charge

8. Projected Test Year Power Supply Costs

Q. Are you sponsoring any exhibits?

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

- Exhibit A-11 Schedule F1 (EWS-1): Projected Cost of Service Allocation Study
- Exhibit A-39 (EWS-2): State Reliability Mechanism Capacity Charge
- Exhibit A-40 (EWS-3): Present & Equalized Revenue / Unit Cost Summary
- Exhibit A-41 (EWS-4): Production Demand Component
- Exhibit A-42 (EWS-5): State Reliability Mechanism 3(b) Offset Calculation
- Exhibit A-43 (EWS-6): Residential Low Income Self-Attestation Form
- Exhibit A-44 (EWS-7): Mitsubishi Electric – Ontonagon Village Housing Case Study

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

A. Yes.

Q. Please describe Exhibit A-11 (EWS-1), Schedule F1.

A. Exhibit A-11 Schedule F1, includes 14 schedules that constitute the fundamentals of the projected test year cost of service study that is prepared for the retail electric jurisdiction, along with the associated allocation methodologies, supplemental analyses, and data.

Q. Please describe Exhibit A-39 (EWS-2).

A. Exhibit A-39 summarizes the calculation of a State Reliability Mechanism Capacity Charge, as required by Section 6w of PA 341.

Q. Please describe Exhibit A-40 (EWS-3).

A. Exhibit A-40 provides an alternate view of the projected test year Cost of Service Study, and details 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.

Q. Please describe Exhibit A-41 (EWS-4).

A. Exhibit A-41 is a subset of the total projected test year COSS presented in the instant case as Exhibit A-11, Schedule F-1, relating only to production demand cost components.

Q. Please describe Exhibit A-42 (EWS-5).

A. Exhibit A-42 summarizes UPPCO's calculation of the offset to capacity related revenue requirement as required by Section 6w of PA 341.

Q. Please describe Exhibit A-43 (EWS-6).

A. Exhibit A-43 is UPPCO's proposed self-attestation form by which customers may qualify for the residential low-income tariff.

Q. Please describe Exhibit A-44 (EWS-7).

A. Exhibit A-44 is a document published by Mitsubishi Electric providing details related to residential electric heat pump installation at the Ontonagon Village Housing facility in Ontonagon, Michigan.

COMPLIANCE WITH PRIOR COMMISSION ORDERS

Q. Please list any incremental issues that the Commission has directed UPPCO to include in its next general rate proceeding and provide a reference to the Company witness who addresses each topic in this proceeding.

A. The Commission, through its Orders in several prior proceedings, has directed UPPCO to include 14 incremental items in its next general rate proceeding. I will list and address or provide reference to each item separately below:

- Case No. U-20276 - Settlement Agreement Paragraph 9(d). *"To the extent that UPPCO issues additional long-term debt in advance of its next general rate proceeding, UPPCO agrees to provide a benefit-cost analysis of the long-term debt alternatives that the Company evaluated as part of its decision analysis in its net general rate case, including the issuance of long-term debt at UPPCO."*
    - This topic is addressed in the direct testimony of Company Witness Haehnel, specifically in the section discussing the debt refinancing plan as required by the Commission Order in U-20995.
- Case No. U-20276 – Settlement Agreement Paragraph 9(g). This paragraph is related to the Tax Cuts and Jobs Act ("TCJA") deferred tax credit. *"The Company will include the entire excess deferred tax regulatory liability within the Company's capital structure as zero cost capital in the next general rate case filing."*
    - This topic is addressed in the direct testimony of Company Witness Haehnel.
- Case No. U-20276 – Settlement Agreement Paragraph 9(i). *"UPPCO shall use a test year pension expense of $1.019 million and shall record any future pension expense below that amount, on a yearly basis, as a regulatory liability to be refunded at a later date as approved by the Commission in the Company's next general rate case."*

- This topic is addressed in the direct testimony of Company Witness Haehnel.

- Case No. U-20276 – Settlement Agreement Paragraph 9(n). *"Prior to filing its next general rate case, UPPCO will perform a Minimum Distribution System ("MDS") study and include the results of the MDS study, all underlying input data, and any other supporting workpapers and analysis, with the documentation addressing Part III of the Rate Case Filing Requirements in Case No. U-18238."*
  - Consistent with the terms of the Commission approved settlement agreement in Case No. U-20276, UPPCO has utilized a consultant to complete a MDS study utilizing the Company's most recent available data. The resulting study report, including all underlying input data and other supporting workpapers, are included within Part III of the filing requirements submitted with the instant proceeding. Additionally, as noted by the "Notice of Preparation of Minimum Distribution Study" that was filed by UPPCO on April 1, 2021, in Case No. U-20276, the Company has fulfilled its requirement to provide notice to the parties in this case that the Company will be performing an MDS study and offer an opportunity to provide input on key parameters to be used in the MDS study.
- Case No. U-20276 – Settlement Agreement Paragraph 9(o). *"UPPCO will perform a load study following the completion of the AMI project and collection of suitable historical data. The results of the load study will be included in UPPCO's next general rate case after the load study is completed."*
  - Phase one of UPPCO's AMI project was materially completed in Q4 2020. Phase one of this project consisted primarily of meter and field area network

installation, along with necessary modifications to the Company's enterprise and billing systems required to enable use of the AMI system for customer billing purposes. Phase two and three of UPPCO's AMI project will allow UPPCO to construct the data repository architecture such that the data obtained from the AMI system may be purposed for other analyses, including load studies. At current state, the AMI project in total is not yet complete, nor has UPPCO collected a suitable period of historical data by which it could perform a load study.

- Case No. U-20276 - Settlement Agreement Paragraph 9(q). *"UPPCO's SRM Capacity charge will be subject to review in the Company's next general rate case. The Company will include the following in its filing: (i) Split power supply costs between fuel, power purchased pursuant to contract, and power obtained from the market, and provide any supporting information necessary to show how the split was conducted and why it is reasonable; (ii) Separately provide the market value of all purchases in the market, Company generation, and purchases pursuant to contract, calculated as hourly LMP times the energy in question; (iii) Identify revenues from ancillary services, and any other of the offsets identified by the Commission previously not addressed; (iv) Make a proposal on the appropriate calculation of the SRM capacity charge pursuant to the Commission's prior direction, notwithstanding it is understood that the Company may make an alternative proposal."*
    - This topic is addressed later in my direct testimony.

- Case No. U-20995 - Settlement Agreement Paragraph 2(h). *"UPPCO under its new ownership shall extend by two months, from the period of May 1, 2022, through June 30, 2022, expiring revenue credits that are currently in UPPCO's base rates provided: (i) UPPCO is authorized to account and record $393,000 per month (i.e. the value of the expiring revenue credits) as a regulatory asset beginning with the month of July 2022 and each month thereafter until 1) rates authorized by a final Commission order in UPPCO's next general rate case become effective or 2) July 1, 2023, whichever occurs first, and (ii) UPPCO is authorized in its next general rate case to recover in rates over an amortization period of two years the total amount recorded to this regulatory asset account including carrying costs equal to UPPCO's weighted average cost of capital."*
    - This topic is addressed later in my direct testimony.
- Case No. U-20995 - Settlement Agreement Paragraph 2(i). *"UPPCO under its new ownership shall actively manage its permanent capital structure (debt and equity) consistent with the capital structure approved by the Commission in the last rate case (U-20276) and address measures intended to reduce the Company's equity percentage in UPPCO's next general rate case to recognize the Staff's and the Attorney General's position for utilities to have a balanced capital structure."*
    - This topic is addressed in the direct testimony of Company Witness Haehnel.
- Case No. U-20995 – Settlement Agreement Paragraph 2(k). *"UPPCO shall, in its next general rate case, include proposals to address the following items from the UP Energy Task Force Committee Recommendations issued March 31, 2021: (1) Propose an Electric Vehicle Charging Station pilot that would explore opportunities*

for joint funding with Michigan Department of Environment, Great Lakes, and Energy Office of Climate and Energy and local interests for highway-oriented DC Fast Charging sites in UPPCO's service territory. *The proposal shall include an analysis of the costs and benefits to ratepayers associated with the proposal. (2) Propose alternative pilot tariffs and/or rebates applicable to building electric space and water heating that recognize differences in cost associated with such service. (3) Propose a low-income residential customer pilot tariff, following consultation with Staff and the Attorney General."*

  - These topics are addressed later in my direct testimony.

- Case No. U-20995 – Settlement Agreement Paragraph 2(l). *"As part of Axium UP's commitment to integrating Environmental, Social and Corporate Governance matters into its management strategy, in its next rate case under its new ownership, UPPCO will forgive 20% of the bad debt booked to the Company's Covid 19 deferred asset account, which shall be borne by shareholders and shall not be recovered from ratepayers."*
  - This topic is addressed in the direct testimony of Company Witness Haehnel.
- Case No. U-20995 – Settlement Agreement Paragraph 2(m). *"UPPCO customers will not be financially responsible for any adverse impacts of any push-down accounting adjustments relating to recording of changes in fair market values or goodwill from the Proposed Transaction."*
  - This topic is addressed in the direct testimony of Company Witness Haehnel.

- Case No. U-20350 – Settlement Agreement Paragraph 19(i*). "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."*
    - This topic is addressed in the direct testimony of Company Witness Haehnel.
- Case No. U-20757 – Commission's April 15, 2020 Order. *"Energy utilities under the rate-regulation of the Commission may begin deferring uncollectible, or bad debt, expense incurred starting March 24, 2020, that are in excess of the amount used to set current rates."*
    - Case No. U-20757 – Commission's August 23, 2022, Order. *"Indiana Michigan Power Company and Upper Peninsula Power Company shall include their novel coronavirus uncollectible expense deferral amounts in their next general rate case."*
    - This topic is addressed in the direct testimony of Company Witness Haehnel.

Q. Does this conclude your summary of incremental topics that must be addressed by UPPCO in this general rate case proceeding?

A. Yes, it does.

U-20995 REGULATORY ASSET

Q. Please describe the impact of the Commission's Order approving settlement in Case No. U-20995 on the expiration of these revenue offsets.

A. The Commission's Order approving settlement in Case No. U-20995 extended the expiration of the revenue offsets for an additional two months, from May 1, 2022, through June 30, 2022. Additionally, the Order authorized the creation of a regulatory asset for the monthly value of the expiring revenue credits beginning in July 2022 and continuing through July 1, 2023, or the effective date of new rates authorized by a Commission Order in UPPCO's next general rate case. Specifically, at Paragraph 2(h) of the approved settlement agreement in U-20995, the Commission stated that:

> *"UPPCO under its new ownership shall extend by two months, from the period of May 1, 2022, through June 30, 2022, expiring revenue credits that are currently in UPPCO's base rates provided: (i) UPPCO authorized to account and record $393,000 per month (i.e., the value of the expiring revenue credits) as a regulatory asset beginning with the month of July 2022 and each month thereafter until 1) rates authorized by a final Commission order in UPPCO's next general rate case become effective or 2) July 1, 2023, whichever occurs first, and (ii) UPPCO is authorized in its net general rate case to recover in rates over an amortization period of two years the total amount recorded to this regulatory asset account including carrying costs equal to UPPCO's weighted average cost of capital."*

Q. Has UPPCO included the total regulatory asset authorized by Case No. U-20995 in its calculation of revenue requirement?

A. Yes. Consistent with the Commission's direction, beginning in July 2022 and continuing through June 2023, UPPCO has accounted for, and will continue to record $393,000 per month to this regulatory asset, resulting in an amount totaling $4,716,000. After including carrying costs equal to UPPCO's weighted average cost of capital of 7.5228%, the resulting total regulatory asset value is $5,075,345. Again, consistent with the

Commission's direction, UPPCO has amortized this amount over a two-year period and included a value of $2,537,673 on line 18 of Schedule A-1.

RESIDENTIAL INCOME ASSISTANCE PROVISION

Q Please describe UPPCO's requirements related to proposing a Residential low-income tariff provision.

A. As described above, Paragraph 2(k) of the Commission approved settlement agreement in Case No. U-20995 requires UPPCO to propose a low-income residential tariff.

Q. What other guidance did UPPCO rely upon in developing its low-income residential tariff proposal?

A. Section 11 (2) of 2016 PA 341 states that:

> *"Notwithstanding any other provision of this act, the Commission may establish eligible low-income customer or eligible senior citizen customer rates. Upon filing of a rate increase request, a utility shall include the proposed eligible low-income customer and eligible senior citizen customer rates and a method to allocate the revenue shortfall attributed to the implementation of those rates upon all customer classes."*

Q. How does the statute define a low-income customer?

A. The statute defines a low-income customer as a customer whose household income does not exceed 150% of the poverty level, as published by the United States Department of Health and Human Services, or who receives any of the following:

1. Assistance from a state emergency relief program
2. Food Stamps

3. Medicaid

Q. Please describe the qualifications for taking service under UPPCO's proposed residential income assistance provision ("RIA").

A. To qualify for UPPCO's proposed RIA a customer must be qualified by the Michigan Department of Health and Human Services for state emergency relief funding. UPPCO will automatically qualify electric customers for the RIA provision upon notification of a customer's eligibility from a qualifying agency. In the absence of such notification, customers will be required to provide adequate documentation of their income status and attest to the accuracy of this information by submitting a completed self-attestation form to the Company. UPPCO's proposed low-income, self-attestation form is sponsored as Exhibit A-43. It will be the customer's responsibility to provide documentation every year to maintain their enrollment in the RIA.

Q. How is the RIA provision structured.

A. Qualifying customers will receive a fixed credit each month equal to the value of the A-1 and AH-1 service charge, presented in the instant case of $29.00 per month.

Q. Please describe the method by which UPPCO allocates the revenue shortfall attributed to the implementation of the RIA provision upon all customer classes, as required by the statute cited above.

A. Upon identification of the expected revenue shortfall attributed to the implementation of the RIA, UPPCO credits a proportional amount of the revenue shortfall to its two residential rate categories, A-1 and AH-1. UPPCO then allocates the total revenue shortfall amount to all rate categories, based upon the total cost of service attributable to each class as specified by the Exhibit A-11, Schedule F1. The net result of this allocation of the resulting revenue shortfall is that the residential class total cost of service is decreased, whereas all other classes experience an increase to cost of service that must be solved through rate design.

Q. Please describe the Company's estimate of eligible low-income customers that may participate in the RIA provision.

A. UPPCO does not collect income information related to its customers. Therefore, the Company must rely upon alternative sources of data to formulate an estimate of eligible low-income customers. Recently, the Company has relied upon data compiled by the United Way as part of their nationwide Asset Limited Income Constrained Employed ("ALICE") report and database of county level population, household, and income information. This data presents households and population data at 100% of federal poverty limit thresholds and approximates similar information at 200% of federal poverty limit via the United Way's definition of ALICE. This data does not explicitly present data at 150% as described by the statute cited above. Therefore, UPPCO is required to use some judgement in determining a reliable estimate of eligible low-income customers. The Company's interpretation of the ALICE data for the ten counties that UPPCO serves, either completely or partially, is that approximately 42% are below 200% of federal poverty level, and approximately 27.4% are at or below 150% of the federal poverty level.

Q. Please define these percentages in terms of the number of RIA eligible UPPCO customers.

A. UPPCO serves approximately 46,605 residential customers. Assuming 27.4% of those customers are at or below 150% of federal poverty level, that equates to approximately 12,770 customer that are eligible for the RIA provision.

Q. What is the resulting revenue deficiency that must be allocated to other customer classes if 12,770 customers were to participate in the RIA provision.

A. The resulting revenue deficiency would total $4.44 million annually.

Q. Would this $4.44 million revenue deficiency be allocated to other customer classes as a result of implementing the RIA provision?

A. Yes. Because Section 11 (2) of 2016 PA 341 requires "*a method to allocate the revenue shortfall attributed to the implementation of those rates upon all customer classes,*" the other customer classes must experience an increase in their total cost of service. UPPCO believes that the magnitude of this potential revenue shortfall that must be allocated to other classes is too large to implement at this time.

Q. Please describe the Company's alternate proposal related to a participation cap in the RIA provision.

A. UPPCO proposes to cap participation in the RIA provision to 2,809 customers. This value is based upon the premise that not all eligible low-income customers will choose to participate in the RIA provision for personal or other reasons outside of the utility's control.

Q. Please describe the resulting revenue deficiency that must be allocated to other customer classes if 2,809 customers were to participate in the RIA provision, consistent with the Company's proposed participation cap.

A. The resulting revenue deficiency to be allocated to all customer classes under UPPCO's proposed cap totals $977,662. UPPCO utilizes this amount in the development of rates included on Exhibit A-11 Schedule F3 as presented by Company Witness Bell. Alternatively, if the Commission does not approve the implementation of UPPCO's proposed cap, then the Company requests that the Commission approve deferred accounting treatment in the form of a regulatory asset plus carrying costs for any RIA provision participation in excess of the Company's proposal.

Q. Please provide the tariff language that UPPCO proposes to include in its residential tariffs A-1 and AH-1.

A. As shown on Exhibit A-11 Schedule F5 sponsored by Witness Bell, the tariff language that UPPCO intends to include in its A-1 and AH-1 tariffs is as follows:

> ***Income Assistance Service Provision (RIA):*** *When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or a self-attestation form. The customer may also qualify for this credit upon confirmation by an authorized State or Federal agency verifying that the customer's total household income does not exceed 150% of the poverty level as*

published by the United States Department of Health and Human Services or if the customer receives any of the following: i) Assistance from a state emergency relief program; ii) Food stamps or iii) Medicaid. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved RIA funding on an annual basis.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: *These charges are applicable to Full Service and Retail Open Access customers.*

Income Assistance Credit: *$(29.00) per customer per month.*

Q. Does the Company's RIA provision satisfy the requirements included in paragraph 2(k) of the approved settlement agreement in Case No. U-20995, as it relates to a low-income tariff proposal?

A. Yes.

ELECTRIC HEATING REBATE PROGRAM

Q. Please describe UPPCO's requirements related to proposing an electric space heating rebate program.

A. Paragraph 2(k) of the Commission approved settlement agreement in Case No. U-20995 requires that UPPCO propose an alternative pilot tariff and or rebate program applicable to building electric space heating and water heating that recognize differences in cost associated with this service in its next general rate case.

Q. Please describe how the Company currently incentivizes the installation of electric heat pumps.

A. Through its Energy Waste Reduction ("EWR") program, UPPCO currently includes incentive funds for current electric space heating customers to replace inefficient resistance-type heating systems with cold-climate heat pumps with great success. Exhibit A-44 outlines a case study of the installation of cold-climate heat pumps installed to replace electric baseboard heating equipment at the Ontonagon Village Housing facility in Ontonagon, Michigan. It is now UPPCO's intent to leverage its experience in replacing electric heating equipment with cold-climate heat pumps across a larger subset of eligible customers.

Q. Please describe UPPCO's Electric Heat Pump Rebate Program that it is proposing in this case.

A. For any existing residential or small commercial customers (taking service under UPPCO's A-1 or C-1 tariff), the Company will provide an up-front incentive in the amount of $2,880 to the customer to decrease the initial cost of installing a cold-climate heat pump as the customer's primary heating source.

Q. Please describe how the up-front incentive amount of $2,880 is derived.

A. On average, UPPCO estimates that a cold-climate heat pump installed within the UPPCO service territory uses approximately 6,000 kWh per year. If a customer who currently utilizes delivered fuels, such as liquid propane, for heating purposes installs a cold-climate heat pump as their primary heating source, then that customer is eligible to be moved to one of UPPCO's electric heating rates, namely AH-1 (residential) or H-1 (small commercial). UPPCO's proposed rebate of $2,880 is derived by multiplying the expected incremental usage of each heat pump by the average rate paid by a residential or small commercial electric heating customer. Once the heat pump equipment is installed, UPPCO will experience an increase in the corresponding rate class level revenue as a result of the new electric heating customer being created.

UPPCO's proposed rebate program is premised upon the idea that the Company will forgo the incremental revenue realized by the creation of a new electric heating customer for two years, as this incremental revenue is provided as an upfront incentive payment to the participating customer. This structure can be described as a revolving bank, whereby the incremental revenue from the first participating customer funds the rebate amount for the second, and so on, until a customer saturation level is achieved.

Q. Please compare UPPCO's proposed rebate for the installation of a heat pump at a customer premises to other similar heat pump rebate programs that the Company is aware of.

A. The Efficiency Maine heat pump rebate program[1] specifies a maximum rebate amount of up to $1,200 dollars for a residential installation, and up to $2,400 in rebates for income-eligible residential customers. UPPCO's proposed rebate of $2,880 exceeds the rebates offered by this comparable rebate program.

[1] https://www.efficiencymaine.com/about-heat-pumps/ (Visited on September 2, 2022).

Q. Please describe any other benefits that would be realized by customers upon installing an electric heat pump as their primary heating source.

A. Cold climate heat pumps provide numerous tangible benefits other than providing building space heating and cooling, such as dehumidification and reduction of particulates and volatile combustion gases within the residence or business. Exhibit A-44 provides a more thorough description of a large-scale electric heat pump installation project within the UPPCO service territory.

Q. Is UPPCO presenting any revenue requirement impact in the projected test year as a result of its Electric Heat Pump Rebate program?

A. No.

Q. Please describe potential future cost-of-service-related implications of increased penetration of electric heat pumps, and the resulting growth in electric heating customer classes.

A. Theoretically, the installation of additional heat pumps at customer premises and growth in the electric heating customer classes will result in a better utilization of existing distribution infrastructure, which would result in downward pressure on distribution revenue requirement, all else being equal.

Q. Does UPPCO's electric heat pump rebate proposal satisfy the requirements included in paragraph 2(k) of the approved settlement agreement in Case No. U-20995?

A. Yes, it does.

ELECTRIC VEHICLE CHARGING PROGRAM UPDATE

Q. Please describe UPPCO's requirements related to implementing an electric vehicle charging program or tariff offering.

A. As described previously in my testimony, the Commission Order in Case No. U-20995 required UPPCO to propose an electric vehicle charging program that would explore opportunities for joint funding promulgated by several State of Michigan agencies.

Q. Please describe UPPCO's actions to date in this regard.

A. On September 15, 2021, UPPCO filed an ex parte application to the Commission for authority to amend its commercial general service tariff to provide expanded use of electric vehicle charging stations. In its application, UPPCO stated that it intended to create a demand waiver within its C-1 tariff, thereby granting UPPCO the ability to expand and offer its Michigan electric customers the ability to install a new electric vehicle charging station and take service under the C-1 tariff. Additionally, in its application the Company requested that the Commission grant the Company authority to create a regulatory asset, whereby the Company will record any necessary contribution, should the customer apply for joint funding through a State of Michigan administered grant program.

Q. Did the Commission approve UPPCO's request in Case No. U-21137?

A. Yes. In its April 14, 2022, Order the Commission approved UPPCO's request, including provisions related to UPPCO's contribution to a particular electric vehicle charging installation in support of a customer's grant funding application and the creation of a regulatory asset in which UPPCO will record such contributions. Finally, in granting its approval, the Commission required that at such time that UPPCO requests recovery of the newly created regulatory asset, that it will file an analysis of the costs and benefits to ratepayers, thereby encompassing the total scope of the requirements set forth by the Commission's May 26, 2021, Order in Case No. U-20995.

Q. Does UPPCO's application in Case No. U-21137 satisfy the requirements of paragraph 2(k) of the approved settlement agreement in Case No. U-20995 as it relates to electric vehicle charging programs that allow for joint funding opportunities?

A. Yes.

Q. Please provide an evaluation of electric vehicle charging-specific tariffs that would be intended to facilitate effective and beneficial electric vehicle charging integration for other customer classes.

A. Fundamentally, an electric vehicle charging-specific tariff can be designed to discourage vehicle charging during peak periods during which energy pricing is high and the existing infrastructure is stressed and encourage charging during off-peak periods during which the energy pricing is typically lower and existing infrastructure is not fully utilized. Furthermore, tariffs that are intended to influence a customer's vehicle charging behavior can also provide meaningful impact on total demand by incentivizing off-peak usage.

Q. Is UPPCO proposing an alternative electric vehicle charging-specific tariff in this proceeding?

A. No. As stated in UPPCO's application in Case No. U-21137, it is UPPCO's intent to observe the behavior of, and usage patterns of, EV charging installations and utilize this information to develop additional electric vehicle charging-specific tariff offerings at a future date once electric vehicles and the required charging facilities reach a higher penetration level throughout UPPCO's service territory.

Q. Please provide an update related to the electric vehicle charging projects that have been installed or are under development as a result of the Commission's approval of UPPCO's request for its C-1 demand waiver.

A. To date, resulting from the implementation of UPPCO's C-1 demand waiver and the joint funding opportunity administered by the State of Michigan, UPPCO has participated in the development of 11 distinct electric vehicle charging infrastructure installations at customer premises. Of these 11 projects, two are currently operational and are located in Munising and Copper Harbor. A third project, located in the City of Houghton, is expected to be completed and operational by the end of September 2022. The remaining nine projects are still under development, and an operational date has not yet been specified.

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.

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, 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.

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-40 – Present Equalized Revenue and Unit Cost Summary.

A. Exhibit A-40 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 multiple rate categories, based upon the bifurcation of customer-related cost components and the resulting rates defined by Exhibit A-40.

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-40 (EWS-3).

A. As shown at lines 37 through 47 of pages 13 through 16 of Exhibit A-40, 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[2]

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

Q. Yes.

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

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

A. Yes. The class cost of service study submitted as Schedule F1 of Exhibit A-11 sponsored by my direct testimony 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 since 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 2019 COSS in Case No. U-20276?

A. Yes. As noted above, in Case No. U-20276 UPPCO proposed, and the Commission approved, the closure of UPPCO's remaining Iron River district specific tariffs (A-2 & Z-4). 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-20276?

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-16.

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-41 – Production Demand Component.

Q. Please provide additional details related to Exhibit A-41 (EWS-4) – Production Demand Component.

A. Exhibit A-41 is a subset of the total projected test year COSS presented in the instant case as Exhibit A-11 Schedule F-1. Exhibit A-41 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-41 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-39 – 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. 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-39, totaling $10.8 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 three 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 four 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-42 – 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 $3.47 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-39.

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-39, as shown by line 27.

Q. Please describe the total SRM capacity charge as calculated by Exhibit A-39.

A. Exhibit A-39 (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, $6.25 Million. At line 34 of Exhibit A-39, the Net Capacity Related Revenue Requirement is divided by UPPCO's 2022/23 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 $52,221 / MW-Year, or $143.07 / 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 Power Supply Cost Recovery ("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-39 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 is apportioned to two categories, Capacity Related and not-Capacity related. The Capacity related revenue requirement is defined by the values included in Schedule A-39, and the not-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.

PROJECTED TEST YEAR POWER SUPPLY COST

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

A. As Company Witness Haehnel explains in his direct testimony, UPPCO has utilized power supply costs for the projected test year that are equal to the costs from the historic year ending December 31, 2021.

Q. Why has UPPCO chosen to use the power supply costs from the historic period as a proxy for the projected test year?

A. UPPCO procures a large portion of its power supply from market sources, and the market is currently extremely volatile. For example, UPPCO recently amended its 2022 PSCR plan primarily due to volatility in MISO energy markets affecting the PSCR cost calculation. In the face of such market volatility, UPPCO believes that any forecast of power supply costs utilized to establish a new PSCR base could be inaccurate. The impact of recent increases in commodity costs have significantly impacted the cost of wholesale electricity, both in terms of actual day-ahead and real-time LMP's at the MISO level, and also in terms of current perceived value of firm energy contracts encompassing future periods. At this time, UPPCO is not certain whether the current pricing trends will persist for the foreseeable future, or whether these pricing trends will return to normal levels before or during the projected test period identified in the instant proceeding.

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

A. No. For the reasons stated previously, 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 2023 PSCR Plan, Case No. U-21267.

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.

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 retail electric rates for	)	**Case No. U-21286**
the generation and distribution of	)	
electricity and other relief.	)	
	)	

DIRECT TESTIMONY OF

NICOLE E. BELL

FOR

UPPER PENINSULA POWER COMPANY

September 8, 2022

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 provided testimony in support of UPPCO's 2020 and 2021 renewable energy cost reconciliation.

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

A. The purpose of my testimony is to present UPPCO's analysis and discussion regarding the following topics:

(i) The development of the Company's current electric sales and peak demand forecast for the period 2023 – 2028.

(ii) The Company's proposed rate design, pursuant to the results of the Company's Cost of Service Study ("COSS") sponsored by Company Witness Stocking.

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 F2.1 (NEB-9):
X. Exhibit A-11, Schedule F2.2 (NEB-10):
XI. Exhibit A-11, Schedule F3.1 (NEB-11):
XII. Exhibit A-11, Schedule F3.2 (NEB-12):

XIII. Exhibit A-11, Schedule F4.1 (NEB-13):

XIV. Exhibit A-11, Schedule F4.2 (NEB-14):

XV. Exhibit A-11, Schedule F5.1 (NEB-15):

XVI. Exhibit A-11, Schedule F5.2 (NEB-16):

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 provides an annual summary of historical service area sales by major customer class for the years 2017 – 2021. This exhibit also summarizes company use and distribution loss kilowatt-hours (“kWh”), and sums to total system output.

Exhibit A-5, Schedule E1.2 provides an annual summary of historical bundled service sales by major customer class for the years 2017 – 2021. This exhibit also summarizes company use and distribution loss kWh, and sums to total system output.

Exhibit A-5, Schedule E1.3 provides an annual summary of historical Alternative Electric Supplier (“AES”) sales by major customer class for the years 2017 – 2021.

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 provides an annual summary of projected service area sales by major customer class for the years 2023 – 2027. This exhibit also summarizes company use and distribution loss kWh, and sums to total system output.

Exhibit A-10, Schedule E1.2 provides an annual summary of projected bundled service sales by major customer class for the years 2023 – 2027. This exhibit also summarizes company use and distribution loss kWh, and sums to total system output.

Exhibit A-10, Schedule E1.3 provides an annual summary of projected AES sales by major customer class for the years 2023 – 2027.

Exhibit A-10, Schedule E2.1 provides an annual summary of total service area system output, maximum demand, and average system load factor for years 2017 – 2027.

Exhibit A-10, Schedule E2.2 provides an annual summary of bundled system output, maximum demand, and average system load factor for years 2017 – 2027.

Q. Please explain how the Company developed its sales forecast for the 12 month projected test period ending June 30, 2024 ("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 April 30, 2022, excluding 2020. The Company excluded 2020 to suppress the nonrecurrent effects of the pandemic on future sales volumes projections. 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.

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 April 30, 2022, excluding 2020. The Company excluded 2020 to suppress the nonrecurrent effects of the pandemic on future sales volumes projections. 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.

The Industrial forecast utilizes a simple moving average method of forecasting that uses historical data from May 1, 2019 – April 30, 2022. 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.

The Company Use forecast utilizes a simple moving average method of forecasting that uses historical data from May 1, 2018 – April 30, 2022. 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.

Given the Company's large-scale replacement of its Sodium Vapor and Metal Halide lighting fixtures to LED that occurred over the last three years, the street lighting forecast is virtually static. As a result, the Company utilizes the most recent year's usage levels to extrapolate the lighting values for the forecast period.

At its most basic level, total lighting sales can be approximated as a function of the following:

- Total number of lighting fixtures deployed, by type and wattage.
- Total wattage consumed by each fixture type, per hour.
- Lighting burn rate in hours, by month per year.

Q. How did the Company project total AES customer sales throughout the forecast period?

A. In 2021, the Company determined there was room under the ten percent cap on retail choice customer participation. 33 customers became AES customers over the course of two rounds that occurred between the months of September through December 2021. With these customer changes, the Company reached the ten percent cap on retail choice customer participation. The

Company assumes total AES sales and demand will remain static at these levels as the customer changes that occurred at the end of 2021 were reflected in the early 2022 AES customer sales. The timeframe used to forecast AES sales for the projected test year is indicative of the Company staying within the ten percent cap on retail choice customer participation.

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 2021 – December 2021. 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 2021 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 2011 – 2021 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, the Company projects a total bundled sales requirement of 531,166,256 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 585,544,990 kWh. This value does not include projected sales to AES customers and the RTMP rate schedule.

Rate Design

Q. Please describe Exhibit A-11, Schedule F2.1.

A. Exhibit A-11, Schedule F2.1 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 June 30, 2024.

Q. Please describe Exhibit A-11, Schedule F2.2.

A. Exhibit A-11, Schedule F2.2 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 June 30, 2025.

Q. Please describe Exhibit A-11, Schedule F3.1.

A. Exhibit A-11, Schedule F3.1 provides a detailed summary of proposed rates by rate schedule for the 12-month period ending on June 30, 2024.

Q. Please describe Exhibit A-11, Schedule F3.2.

A. Exhibit A-11, Schedule F3.2 provides a detailed summary of proposed rates by rate schedule for the 12-month period ending on June 30, 2025.

Q. Please describe Exhibit A-11, Schedule F4.1.

A. Exhibit A-11, Schedule F4.1 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 June 30, 2024.

Q. Please describe Exhibit A-11, Schedule F4.2.

A. Exhibit A-11 (NEB-9) Schedule F4.2 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 June 30, 2025.

Q. Please describe Exhibit A-11, Schedule F5.1.

A. Exhibit A-11, Schedule F5.1 contains redline versions of the tariff sheets consistent with the Company's proposed rate design for the 12-month period ending on June 30, 2024.

Q. Please describe Exhibit A-11, Schedule F5.2.

A. Exhibit A-11, Schedule F5.2 contains redline versions of the tariff sheets consistent with the Company's proposed rate design for the 12-month period ending on June 30, 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.

1. Allocation of Rate Increases, Informed by the UPPCO COSS sponsored by Company witness Stocking;
2. Rate Design for the A-1 Residential Rate Schedule;
3. Rate Design for the AH-1 Residential Heating Rate Schedule;
4. Rate Design for the C-1 General Service Rate Schedule;
5. Rate Design for the H-1 Commercial Heating Rate Schedule;

6. Rate Design for the P-1 Light and Power Rate Schedule;
7. Rate Design for the CP-U Rate Schedule;
8. Rate Design for the WP-3 Rate Schedule;
9. Rate Design for the RTMP Rate Schedule;
10. Rate Design for the SL-3, SL-5, & SL-6 Rate Schedule;
11. 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, as reflected in Exhibit A-40 sponsored by Company witness Stocking, the projected test year COSS indicates that UPPCO's present customer charges 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-40.

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 24 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 June 30, 2024.

A. As evidenced by page 6 of Exhibit A-11, Schedule F1 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 20.78%. UPPCO's proposed rate design for A-1 derives a Service Charge of $29.00 per month, and a total volumetric energy rate of $0.08151 / kWh. The details related to the proposed rate design calculation for the A-1 schedule are shown in Exhibit A-11, Schedule F3.1.

Q. Please describe UPPCO's proposed rate design for the A-1 rate schedule for the 12-month period ending on June 30, 2025.

A. As evidenced by page 6 of Exhibit A-11, Schedule F1 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 20.78%. UPPCO's proposed rate design for A-1 derives a Service Charge of $29.00 per month, and a total volumetric energy rate of $0.12088 / kWh. The details related to the proposed rate design calculation for the A-1 schedule are shown in Exhibit A-11, Schedule F3.2.

Q. Please describe UPPCO's proposed rate design for the AH-1 rate schedule for the 12-month

period ending on June 30, 2024.

A. As evidenced by page 6 of Exhibit A-11, Schedule F1, the current rate levels within the AH-1 schedule are forecasted to under-recover the revenue requirement for this rate schedule by 45.85%. UPPCO's proposed rate design for AH-1 derives a Service Charge of $29.00 per month, total energy rate of $0.08151 for June – September, a total energy rate of $0.08151 for all kWh less than 500 kWh during the heating season, and a total energy rate of $0.04076 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 F3.1.

Q. Please describe UPPCO's proposed rate design for the AH-1 rate schedule for the 12-month period ending on June 30, 2025.

A. As evidenced by page 6 of Exhibit A-11, Schedule F1, the current rate levels within the AH-1 schedule are forecasted to under-recover the revenue requirement for this rate schedule by 45.85%. UPPCO's proposed rate design for AH-1 derives a Service Charge of $29.00 per month, total energy rate of $0.12088 for June – September, a total energy rate of $0.12088 for all kWh less than 500 kWh during the heating season, and a total energy rate of $0.06044 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 F3.2.

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 25% 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 outlined by Exhibit A-40, this practice is consistent with prior Commission direction.

Q. Please describe UPPCO's proposed rate design for the C-1 rate schedule for the 12-month period ending on June 30, 2024.

A. As evidenced by page 6 of Exhibit A-11, Schedule F1, the current rate levels within the C-1 schedule are forecasted to under-recover the revenue requirement for this rate schedule by 44.27%. UPPCO's proposed rate design for C-1 derives a Service Charge of $38.00, and a total energy rate of $0.08762 per kWh. The details related to the proposed rate design calculation for the C-1 schedule are shown in Exhibit A-11, Schedule F3.1.

Q. Please describe UPPCO's proposed rate design for the C-1 rate schedule for the 12-month period ending on June 30, 2025.

A. As evidenced by page 6 of Exhibit A-11, Schedule F1, the current rate levels within the C-1 schedule are forecasted to under-recover the revenue requirement for this rate schedule by 44.27%. UPPCO's proposed rate design for C-1 derives a Service Charge of $38.00, and a total energy rate of $0.14232 per kWh. The details related to the proposed rate design calculation for the C-1 schedule are shown in Exhibit A-11, Schedule F3.2.

Q. Please describe UPPCO's proposed rate design for the H-1 rate schedule for the 12-month period ending on June 30, 2024.

A. As evidenced by page 6 of Exhibit A-11, Schedule F1, the current rate levels within the H-1 schedule are forecasted to under-recover the revenue requirement for this rate schedule by 56.38%. UPPCO's proposed rate design for H-1 derives a Service Charge of $38.00 per month, a total energy rate of $0.08762 per kWh for June – September, a total energy rate of $0.08762 for all kWh less than 1,000 kWh during the heating season, and a total energy rate of $0.04381 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-16, Schedule F3.1.

Q. Please describe UPPCO's proposed rate design for the H-1 rate schedule for the 12-month period ending on June 30, 2025.

A. As evidenced by page 6 of Exhibit A-11, Schedule F1, the current rate levels within the H-1 schedule are forecasted to under-recover the revenue requirement for this rate schedule by 56.38%. UPPCO's proposed rate design for H-1 derives a Service Charge of $38.00 per month, a total energy rate of $0.14232 per kWh for June – September, a total energy rate of $0.14232 for all kWh less than 1,000 kWh during the heating season, and a total energy rate of $0.07116 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-16, Schedule F3.2.

Q. Were rate schedules C-1 and H-1 solved concurrently to mitigate the significant rate increase to recover required revenues experienced by H-1?

A. Yes, they were.

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-40, this practice is consistent with prior Commission direction.

Q. Please describe UPPCO's proposed rate design for the P-1 rate schedule for the 12-month period ending on June 30, 2024.

A. As evidenced by page 6 of Exhibit A-11, Schedule F1, the current rate levels within the P-1 schedule are forecasted to over-recover the revenue requirement for this rate schedule by 13.73%. UPPCO's proposed rate design for P-1 derives a Service Charge of $50.00 per month, total demand charges of $6.85 per kW, and a total Energy Charge of $0.03323 per kWh. The details related to the proposed rate design calculation for the P-1 schedule are shown in Exhibit A-11, Schedule F3.1.

Q. Please describe UPPCO's proposed rate design for the P-1 rate schedule for the 12-month period ending on June 30, 2025.

A. As evidenced by page 6 of Exhibit A-11, Schedule F1, the current rate levels within the P-1 schedule are forecasted to over-recover the revenue requirement for this rate schedule by 13.73%. UPPCO's proposed rate design for P-1 derives a Service Charge of $50.00 per month, total demand charges of $5.80 per kW, and a total Energy Charge of $0.07007 per kWh. The details related to the proposed rate design calculation for the P-1 schedule are shown in Exhibit A-11, Schedule F3.2.

Q. Please describe UPPCO's proposed rate design for the CP-U rate schedule for the 12-month period ending on June 30, 2024.

A. As evidenced by page 7 of Exhibit A-11, Schedule F1, the current rate levels within the CP-U schedule are forecasted to under-recover the revenue requirement for this rate schedule by 38.87% in CP-U Secondary, over-recover the revenue requirement for this rate schedule by 11.74% in CP-U Primary, and under-recover the revenue requirement for this rate schedule by 55.09% 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 $4.32 per kW, total interruptible demand charges of $4.32 per kW, total customer demand charge of $4.11 per kW, an on-peak energy charge of $0.08186 per kWh, and an off-peak energy charge of $0.05323 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 $3.56 per kW, total interruptible demand charges of $3.56 per kW, total customer demand charge of $3.38 per kW, an on-peak energy charge of $0.07891 per kWh, and an off-peak energy charge of $0.05130 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 $1.74 per kW, total interruptible demand charges of $1.74 per kW, total substation transformer capacity charge of $1.04 per kVA, an on-peak energy charge of $0.07602 per kWh, and an off-peak energy charge of $0.04941 per kWh. The details related to the proposed rate design calculation for the CP-U schedule are shown in Exhibit A-11, Schedule F3.1.

Q. Please describe UPPCO's proposed rate design for the CP-U rate schedule for the 12-month period ending on June 30, 2025.

A. As evidenced by page 7 of Exhibit A-11, Schedule F1, the current rate levels within the CP-U schedule are forecasted to under-recover the revenue requirement for this rate schedule by 38.87% in CP-U Secondary, over-recover the revenue requirement for this rate schedule by 11.74% in CP-U Primary, and under-recover the revenue requirement for this rate schedule by 55.09% 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 $5.14 per kW, total interruptible demand charges of $5.14

per kW, total customer demand charge of $4.89 per kW, an on-peak energy charge of $0.08428 per kWh, and an off-peak energy charge of $0.05480 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 $4.23 per kW, total interruptible demand charges of $4.23 per kW, total customer demand charge of $4.02 per kW, an on-peak energy charge of $0.08124 per kWh, and an off-peak energy charge of $0.05281 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 $2.07 per kW, total interruptible demand charges of $2.07 per kW, total substation transformer capacity charge of $1.04 per kVA, an on-peak energy charge of $0.07827 per kWh, and an off-peak energy charge of $0.05087 per kWh. The details related to the proposed rate design calculation for the CP-U schedule are shown in Exhibit A-11, Schedule F3.2.

Q. Please describe UPPCO's proposed rate design for the WP-3 rate schedule for the 12-month period ending on June 30, 2024.

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 27.51%. 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 $1.60 per kW, total interruptible demand charges of $1.60 per kW, substation transformer capacity of $1.04 per KVA, total on-peak energy charges of $0.07602 per kWh, and total off-peak energy charges of $0.04941 per kWh. The details related to the proposed rate design calculation for the WP-3 schedule are shown in Exhibit A-11, Schedule F3.1.

Q. Please describe UPPCO's proposed rate design for the WP-3 rate schedule for the 12-month period ending on June 30, 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 27.51%. 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 $1.90 per kW, total interruptible demand charges of $1.90 per kW, substation transformer capacity of $1.04 per KVA, total on-peak energy charges of $0.07827 per kWh, and total off-peak energy charges of $0.05087 per kWh. The details related to the proposed rate design calculation for the WP-3 schedule are shown in Exhibit A-11, Schedule F3.2.

Q. Were rate schedules P-1, CP-U and WP-3 solved concurrently to mitigate the significant rate increase to recover required revenues experienced by the rate classes?

A. Yes, they were.

Q. What is the Company's justification for increasing the Industrial 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-40, this practice is consistent with prior Commission direction.

Q. Please describe UPPCO's proposed rate design for the RTMP rate schedule for the 12-month period ending on June 30, 2024.

A. As evidenced by page 7 of Exhibit A-11, Schedule F1, the current rate levels within the RTMP rate schedule are forecasted to under-recover the revenue requirement for this schedule by 33.60%. UPPCO's proposed rate design for the RTMP schedule derives a monthly customer charge of $1,000.00 per month, a demand charge of $0.27 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 F3.1.

Q. Please describe UPPCO's proposed rate design for the RTMP rate schedule for the 12-month period ending on June 30, 2025.

A. As evidenced by page 7 of Exhibit A-11, Schedule F1, the current rate levels within the RTMP rate schedule are forecasted to under-recover the revenue requirement for this schedule by 33.60%. UPPCO's proposed rate design for the RTMP schedule derives a monthly customer charge of $1,000.00 per month, a demand charge of $0.34 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 F3.2.

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. UPPCO over the last several years has replaced the vast majority of the Sodium Vapor and Metal Halide lighting fixtures with LED equivalents. In response to customer requests, in the present case, UPPCO has added LED fixture rates for a 400W LED and a 1,000W LED. The resulting rates are outlined in Schedule F3.1 and Schedule F3.2 of Exhibit A-11.

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 June 30, 2024?

A. As evidenced by Schedule F4.1 of Exhibit A-11, a residential customer, previously taking service under the A-1 tariff, consuming 500 kWh per month will receive a monthly bill of $126.58. This constitutes an increase of $12.43, or 10.89% when compared to present revenues.

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 June 30, 2025?

A. As evidenced by Schedule F4.2 of Exhibit A-11, a residential customer, previously taking service under the A-1 tariff, consuming 500 kWh per month will receive a monthly bill of $146.26. This constitutes an increase of $19.68, or 15.55% when compared to the first year of new rate implementation 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 June 30, 2024?

A. As evidenced by Schedule F4.1 of Exhibit A-11, a C-1 customer consuming 2,500 kWh per month will receive a monthly bill of $515.53. This constitutes an increase of $84.93, or 19.72% compared to a similarly calculated bill at current rates.

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 June 30, 2025?

A. As evidenced by Schedule F4.2 of Exhibit A-11, a C-1 customer consuming 2,500 kWh per month will receive a monthly bill of $652.26. This constitutes an increase of $125.76, or 23.89% when compared to a similarly calculated bill at rates from the first year of new rate implementation.

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 June 30, 2024?

A. As evidenced by Schedule F4.1 of Exhibit A-11, a P-1 customer consuming 20,000 kWh, and 55 kW per month will receive a monthly bill of $3,047.91. This constitutes an increase of $15.00, or 0.49% 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 June 30, 2025?

A. As evidenced by Schedule F4.2 of Exhibit A-11, a P-1 customer consuming 20,000 kWh, and 55 kW per month will receive a monthly bill of $3,665.75. This constitutes an increase of $617.84, or 20.27% compared to a similarly calculated bill at rates from the first year of new rate implementation.

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 June 30, 2024?

A. As evidenced by Schedule F4.1 of Exhibit A-11, a CP-U customer consuming 480,000 kWh, and

1,260 kW per month will receive a monthly bill of $52,314.54. This constitutes an increase of $6,321.02, or 13.74% 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 June 30, 2025?

A. As evidenced by Schedule F4.2 of Exhibit A-11, a CP-U customer consuming 480,000 kWh, and 1,260 kW per month will receive a monthly bill of $54,923.64. This constitutes an increase of $2,609.10, or 4.99% compared to a similarly calculated bill at rates from the first year of new rate implementation.

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 June 30, 2024?

A. As evidenced by Schedule F4.1 of Exhibit A-11, an SL-6 customer with one 100-Watt LED fixture, one pole, and one span of conductor will receive a monthly bill of $10.21. This constitutes a decrease of $7.87, or -43.53%.

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 June 30, 2025?

A. As evidenced by Schedule F4.2 of Exhibit A-11, an SL-6 customer with one 100-Watt LED fixture, one pole, and one span of conductor will receive a monthly bill of $10.21. This rate will stay the same between year 1 and year 2 of rate implementation.

Q. Are the proposed rates for the 12-month period ending on June 30, 2024, 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 A1.1, to the extent practical?

A. Yes.

Q. Are the proposed rates for the 12-month period ending on June 30, 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 A1.2, to the extent

practical?

A. Yes.

Q. Does this complete your direct testimony in this proceeding?

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 and distribution of electricity and other relief.	)))))	Case No. U-21286

PROOF OF SERVICE

STATE OF MICHIGAN)
)ss
COUNTY OF INGHAM)

Allison Kellogg, being first duly sworn, deposes and states that on September 8, 2022, she served a copy of the following:

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 of Gradon R. Haehnel, Natasha L. Wonch, Stephen S. Lillie, Jay R. Ringler, Adrian M. McKenzie, Kay L. Ryan, Eric W. Stocking and Nicole E. Bell;
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 and Paul M. Collins;

together with this Proof of Service upon the parties set forth on the attached **Service List** via electronic mail.

I declare that the foregoing statement is true to the best of my knowledge, information and belief.

Allison Kellogg

Digitally signed by: Allison Kellogg
DN: CN = Allison Kellogg email = kellogg@millercanfield.com C = US O = Miller Canfield
Date: 2022.09.08 14:41:59 -04'00'

Allison Kellogg

Subscribed and sworn before me
On this 8thth day of September, 2022.

Elizabeth H. Kunc

Digitally signed by: Elizabeth H. Kunc
DN: CN = Elizabeth H. Kunc email = kunc@millercanfield.com C = US O = Miller Canfield
Date: 2022.09.08 14:42:51 -04'00'

Elizabeth H. Kunc
Notary Public – State of Michigan
My Commission Expires: October 9, 2025
County of Eaton – Acting in County of Ingham

S T A T E O F M I C H I G A N
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
*****

In the matter of the application of	)	
UPPER PENINSULA POWER COMPANY	**)**	Case No. U-21286
for authority to increase its rates for	)	
the generation and distribution of	)	
electricity and other relief.	)	

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MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

ENTRY OF APPEARANCE IN AN ADMINISTRATIVE HEARING

This form is issued as provided for by 1939 PA 3, as amended, and by 1933 PA 254, as amended. The filing of this form, or an acceptable alternative, is necessary to ensure subsequent service of any hearing notices, Commission orders, and related hearing documents.

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 Docket No. U-21286

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Upper Peninsula Power Company
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Paul Collins

Address One Michigan Ave., Ste. 900
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Date 09/07/2022

Signature: Paul M. Collins Digitally signed by: Paul M. Collins DN: CN = Paul M. Collins email = collinsp@millercanfield.com C = US O = Miller Canfield Date: 2022.09.08 14:43:14 -04'00'

☐ I am not an attorney

☑ I am an attorney whose:

Michigan Bar # is P-69719

______ Bar # is: ______
(state)

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EAHR1 - 09/29/2016

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

ENTRY OF APPEARANCE IN AN ADMINISTRATIVE HEARING

This form is issued as provided for by 1939 PA 3, as amended, and by 1933 PA 254, as amended. The filing of this form, or an acceptable alternative, is necessary to ensure subsequent service of any hearing notices, Commission orders, and related hearing documents.

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 Docket No. U-21286

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Upper Peninsula Power Company
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Sherri A. Wellman

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Date 09/07/2022

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Date: 2022.09.08 14:43:39 -04'00'

○ I am not an attorney

◉ I am an attorney whose:

Michigan Bar # is P-38989

_____________ Bar # is: _____________
(state)