Founded in 1852
by Sidney Davy Miller

MILLER CANFIELD

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September 21, 2018

Ms. Kavita Kale
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway, 3rd Floor
Lansing, MI 48917

Re: Upper Peninsula Power Company
2018 Rate Case
MPSC Case No. U-20276

Dear Ms. Kale:

Enclosed for electronic filing in the above matter are:

(1) Application;
(2) Notice of Hearing;
(3) Affidavit of Gradon R. Haehnel;
(4) Direct Testimony of James C. Larsen;
(5) Direct Testimony and Exhibits of Nicholas E. Kates, Gradon R. Haehnel, Eric W. Stocking, Keith E. Moyle, Jason Brynick, and Adrien M. McKenzie;
(6) Documentation which complies with Part II of the Rate Case Filing Requirements established by the Commission's order dated July 31, 2017, issued in Case No. U-18238;
(7) Protective Order; and
(8) Appearances of Sherri A. Wellman, Paul M. Collins, Matthew S. Carstens.

A compact disc containing this filing; workpapers in native electronic format, and documentation addressing Part III of the Rate Case Filing Requirements in Case No. U-18238; is being served today on the Commission Staff and all intervening parties in Case No. U-17895, the Company's last electric rate case.

The proposed Notice of Hearing has also been e-mailed to Angela Sanderson.

If you have any questions, please call me at the number above, or call Paul M. Collins at (517) 483-4908.

Very truly yours,

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

Paul Collins

Digitally signed by: Paul Collins
DN: CN = Paul Collins email = collinsp@millercanfield.com C = US
Date: 2018.09.21 09:47:31 -04'00'

By: ______________________________

Paul M. Collins

PMC/kf
Enclosures
cc: Gradon Haehnel

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.	))))	Case No. U-20276

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 54,000 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 Upper Peninsula Power Holding Company ("UPPHC"). UPPHC acquired UPPCO pursuant to an Order Approving Settlement Agreement issued June 6, 2014, in Case No. U-17564, in which the Commission approved, pursuant to Section 6q of 2008 PA 286, MCL 460.6q, the sale of UPPCO by Integrys Energy Group, Inc.

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 dated September 8, 2016, in Case No. U-17895. That Order granted rate relief of $4,647,975 million annually, based on a 10.00% return on common equity, effective September 23, 2016. The Commission approved rates were based on a 2016 test year.

6. UPPCO's rates for retail electric service established in Case No. U-17895 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 2019 calendar test year. Using a 2019 test year and a return on common equity of 10.5%, UPPCO calculates a base rate

revenue deficiency of $9,982,604. Therefore, UPPCO requests the Commission authorize the Company to adjust its retail electric rates so as to provide additional revenue in the amount of $9,982,604 annually, an overall retail rate increase of approximately 9.71%. UPPCO represents that such an increase is just and reasonable under the circumstances, and is necessary to provide a reasonable return on UPPCO's electric utility plant and resources required to provide service in Michigan.

8. The key drivers contributing to this revenue deficiency are (a) declining sales volumes, and (b) the necessity of continuing investment in reliability infrastructure, including Advanced Metering Infrastructure (AMI). In addition to UPPCO's continuing efforts to reduce costs and to minimize the amount of rate relief required, UPPCO proposes to mitigate the rate impact of these drivers on and to pass cost savings through to its customers through the following: (a) Tax Cut and Jobs Act (TCJA) savings of approximately $0.9 million pursuant to the Company's Calculation C filing requirement, and (b) lower depreciation and amortization expense of approximately $1.8 million, consistent with the Company's proposal in the concurrent depreciation rate proceeding in Case No. U-18467.

9. UPPCO represents that in order to establish rates for retail electric service which 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 $9,982,604, an overall retail rate increase of approximately 9.71%.

10. 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 UPPCO further represents that rate relief is required to permit UPPCO to continue to achieve its goal of rendering adequate retail electric service to the public; and 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.

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-16. 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-16. UPPCO requests Commission approval of the proposed rates.

12. In addition, UPPCO proposes various revisions to its electric tariffs, including to (a) consolidate the residential rate schedules A-1 and A-2 classes of the Integrated and Iron River divisions; (b) consolidate the dusk to dawn outdoor security lighting service rate Schedules Z-3 and Z-4; (c) add a new Distribution Generation Rider tariff pursuant to the Order in Case No. U-18383; (d) modify its current Parallel Generation (i.e., net metering) tariffs pursuant to the Order in Case No. U-18383, and (e) establish a new Power Supply Cost Recovery (PSCR) base rate.

IMPLEMENTATION OF RATES

13. UPPCO proposes to implement its revised rates no later than July 21, 2019, 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 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 10.5%;

D. Authorize UPPCO to file and make effective, at the earliest possible date, but no earlier than July 21, 2019, 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; Grant UPPCO such other and further relief and authorizations as may be lawful and proper.

Respectfully submitted,

UPPER PENINSULA POWER COMPANY

Paul Collins

Digitally signed by: Paul Collins
DN: CN = Paul Collins email = collinsp@millercanfield.com C = US
Date: 2018.09.21 11:45:45 -04'00'

Dated: September 21, 2018

By:____
One of Its Attorneys

Sherri A. Wellman (P38989)
Paul M. Collins (P69719)
Matthew S. Carstens (P61070)
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
NO. U-20276

- Upper Peninsula Power Company (UPPCO) requests Michigan Public Service Commission approval to increase its retail rates for the generation and distribution of electricity and for 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 Drive, Marquette, Michigan 49855, (800) 562-7680 for a free copy of its application. Any person may review the application at the offices of UPPCO.

- The prehearing conference in this matter will be held:

DATE/TIME:	**_____________, ________, 2018, at _____ a.m.** This hearing will be a prehearing conference to set future hearing dates and decide other procedural matters.
BEFORE:	Administrative Law Judge _______________
LOCATION:	Michigan Public Service Commission 7109 West Saginaw Highway Lansing, Michigan 48917
PARTICIPATION:	Any interested person may attend and participate. The hearing site is accessible, including handicapped parking. Persons needing any accommodation to participate should contact the Commission's Executive Secretary at (517) 284-8090 in advance to request mobility, visual, hearing or other assistance.

The Michigan Public Service Commission (Commission) will hold a hearing to consider UPPCO's September 21, 2018 application for approval to increase its rates for the sale of electricity. UPPCO seeks Commission approval to: 1) adjust its retail electric rates so as to provide additional revenue of $9.983 million annually above levels established in Case No. U-17895 based on a projected 12-month test year ending December 31, 2019; 2) to adjust its existing retail rates so as to produce a rate of return on common equity of not less than 10.5%; 3) continue investment in reliability infrastructure, including Advanced Metering Infrastructure; 4) pass Tax Cuts and Jobs Act savings to customers through the "Calculation C" filing requirement; and 5) pass depreciation cost savings to customers through implementation of depreciation cost savings to customers through implementation of depreciation rates currently proposed by UPPCO in MPSC Case No. U-18467. UPPCO also proposed various revisions to its electric service rates, rules and regulations, which include the consolidation of rate classes between UPPCO's Integrated and Iron River districts.

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 **October ___, 2018**. (Petitions to intervene may also be filed using the traditional paper format.) The proof of service shall indicate service upon UPPCO's attorney, Sherri A. Wellman, at Miller, Canfield Paddock & Stone, P.L.C., One Michigan Avenue, Suite 900, Lansing, MI 48933.

Any person wishing to appear at the hearing to make a statement of position without becoming a party to the case may participate by filing an appearance. To file an appearance, the individual must attend the hearing and advise the presiding administrative law judge of his or her wish to make a statement of position. 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.

Requests for adjournment must be made pursuant to the Commission's Rules of Practice and Procedure R 792.10422 and R 792.10432. Requests for further information on adjournment should be directed to (517) 284-8130.

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

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

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

__________________, 2018

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **UPPER PENINSULA POWER COMPANY** for authority to increase electric rates.	))))	Case No. U-20276

CERTIFICATION OF GRADON R. HAEHNEL

Gradon R. Haehnel, Director of Regulatory Affairs 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.

Dated: September 21, 2018

Gradon R. Haehnel

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** for authority to increase retail electric rates.	))))	Case No. U-20276

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. 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 exhibits pertaining to Part III of its Application materials and testimony describing the Protected Material. Subject to challenge under Paragraph IV.A, Protected Material also includes 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 officer or the Michigan Public Service Commission (MPSC or Commission), in testimony or exhibits filed later in this case, or in arguments of counsel.

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

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

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), Michigan Attorney General, or any other person, company, organization, or association that is granted intervention in this Case No. U-20276 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: 1) the Protected Material; 2) any copy or reproduction of the Protected Material made by any person; and 3) 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 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 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 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 ON [INSERT DATE] IN CASE NO. U-20276." 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-20276." 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.

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 only to the extent permitted by law. If any person files a request under the Freedom of Information Act with the MPSC or the Michigan Attorney General seeking access to documents subject to this Protective Order, the MPSC's Executive Secretary, Staff, or the Attorney General shall immediately 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 MPSC, its Staff, and/or the Michigan Attorney General grant the request in full or in part.

IV. Termination of Protected Status

A. A Receiving Party reserves the right to challenge whether a document or information is Protected Material and whether this information can be withheld under this Protective Order. In response to a motion or on its own initiative, the Commission or the presiding officer in this case may revoke a document's protected status after notice and hearing. If the presiding 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, then 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 this Case No. U-20276 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.

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.l through I.B.5. 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: 1) contact the Disclosing Party's counsel of record and obtain written permission to disclose the information, or 2) 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 immediately notifying the MPSC, the presiding 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.

____

Administrative Law Judge

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-20276
for authority to increase retail electric rates.	)	
	)	

NONDISCLOSURE CERTIFICATE

By signing this Nondisclosure Certificate, I acknowledge that access to Protected Material is provided to me under the terms and restrictions of the Protective Order issued in Case No. U-20276, 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: ____________________ ____________________________________

Title:

Representing:

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.	)	Case No. U-20276
	)	

DIRECT TESTIMONY AND EXHIBITS OF

JAMES C. LARSEN

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

September 21, 2018

Q. Please state your full name and business address?

A. James C. Larsen, 1002 Harbor Hills Drive, Marquette, MI 49855.

Q. What is your business title and by whom are you employed?

A. My title is President, Chief Executive Officer for Upper Peninsula Power Company ("UPPCO" or the "Company").

Q. Please describe your educational background and business experience.

A. I hold a Bachelor of Science Degree in Mechanical Engineering from Clarkson University, located in Potsdam, NY. I graduated from Navy Nuclear Power School's Officer Program, located in Orlando, FL, as a civilian. I also hold a Master of Business Administration (MBA) Degree from the University of Colorado at Colorado Springs. I currently hold Professional Engineer License's in the State of Michigan and the State of Alaska.

I was employed by General Electric ("GE") (the GE business group that I worked for was later sold to Lockheed Martin) from 1987 to 1999. My duties involved the supervision, operations, and maintenance of a Navy nuclear power plant at the Knolls Atomic Power Laboratory in West Milton, NY. From 1996 through 1999, I held the position of a Nuclear Plant Supervisor in which I was the senior person on-site responsible for the safe operation of a nuclear power plant.

From 1999 to 2016, I performed various roles of increasing responsibility for SEMCO Energy Gas Company in Port Huron, Michigan. My various roles included President (2010-2016), Vice President of Operations (2009-2010) and Director of Engineering (2006-2009). I also served as President and Board Chairman for SEMCO Energy Gas Storage Company, Board Manager for Cook

Inlet Natural Gas Storage Alaska and President and Board Chairman for Hot Flame Gas, Inc (regional propane distribution in Upper Michigan and Wisconsin). Since 2017, I have been serving in the role of President and Chief Executive Officer and Board Member for UPPCO in Marquette, MI.

Q. Have you previously testified before the Michigan Public Service Commission (the "MPSC" or the "Commission")?

A. Yes, I filed testimony in Case Nos. U-13960, U-14402, U-14718 and U-14893.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of UPPCO.

Q. What is your role in this proceeding?

A. As the Company's chief policy witness, with substantial input from others, I set the overall direction for this filing. This includes making various policy choices identified in this testimony. The Company's witnesses did their work on this filing based on my direction and consistent with exercising their own professional judgment.

Q. What subject matter will you be addressing?

A. I will be addressing the following at a high-level:

(1) UPPCO's request for rate relief, and the primary drivers including:

(a) customer usage,

(b) the Tax Cuts and Jobs Act (TCJA) of 2017,

(c) investment in company infrastructure,

(2) an accounting change related to the Escanaba River Hydro facilities,

(3) the Company's Advanced Metering Infrastructure ("AMI") project,

(4) UPPCO's updated cost of service study, rate design and return on equity ("ROE"),

(5) an update on the $26 million Revenue Offset,

(6) an update on UPPCO's reliability programs.

Q. Concerning the subject matter that you will be addressing, what witnesses on behalf of UPPCO are providing additional support and testimony?

A. The following witnesses are sponsoring pre-filed testimony on behalf of UPPCO on the topics I describe:

- Mr. Nicholas E. Kates – Mr. Kates's testimony is presenting UPPCO's 2017 historical test year revenue requirement and UPPCO's 2019 projected test year revenue requirement.
- Mr. Keith E. Moyle – Mr. Moyle is sponsoring testimony and exhibits on UPPCO's capital infrastructure expenditures focused on improving reliability, as well as, UPPCO's line clearance program.
- Mr. Gradon R. Haehnel – Mr. Haehnel is supporting (1) UPPCO's depreciation and amortization expense decrease, (2) UPPCO's revenue offset (credit) update, (3) UPPCO's accounting change of its Escanaba Hydro Facilities, (4) UPPCO's cost of service study update, and (5) the Company's Advanced Meter Infrastructure (AMI) project and business.
- Mr. Eric W. Stocking – Mr. Stocking is sponsoring testimony and exhibits on sales and peak demand forecasting, rate design, and the establishment of a new Power Supply Cost Recovery (PSCR) base rate.

- Mr. Jason Brynick – Mr. Brynick is sponsoring testimony and exhibits on the AMI project.
- Mr. Adrien McKenzie – Mr. McKenzie presents an independent assessment of the fair and reasonable rate of return on equity ("ROE") for the jurisdictional electric utility operations of UPPCO.

Q. Please summarize UPPCO's proposal in this proceeding.

A. UPPCO is requesting that the Commission approve an annual increase in retail revenues of approximately $9.98 million. The amount is based on a projected calendar test year ending December 31, 2019 and is primarily driven by the need to adjust rates to reflect recent decreasing sales, Tax Cuts and Jobs Act (TCJA) tax benefits, lower depreciation rates and system infrastructure investments made and currently underway to enhance the reliability of UPPCO's service. The Company is also requesting a fair opportunity to earn a return on equity of 10.5%.

Q. When did UPPCO last increase its base rates?

A. The MPSC authorized an increase to UPPCO's base rates in 2016 for an amount of $4.65 million.

Q. What is the effect of this proposed increase on an average residential customer who uses 500 kWh a month?

A. The proposed increase will increase rates for a residential customer who uses 500 kWh a month by 2.72%.

Q. Please summarize UPPCO's proposed annual base revenue increase.

A. UPPCO is requesting an increase of $9.98 million to achieve revenues of approximately to $112.80 million. When compared to the retail revenues authorized in Case No. U-17895 ("2016 Rate Case"), UPPCO is requesting retail revenues approximately $9.18 million less than previously approved levels.

Q. Please discuss the significant drivers for this case.

A. There are three primary drivers for the need to file the case.

1. Adjusting retail rates based on projected volumes and the Company's updated cost of service study;
2. Reducing costs to complete the roll in of all tax savings resulting from the TCJA of 2017; and
3. Recovering costs for continued investment in Company infrastructure.

Q. Please explain the need to adjust retail rates for projected volumes (i.e., lower sales)?

A. UPPCO has experienced significantly lower sales than what was forecasted and used in the 2016 Rate Case to set rates. In addition, UPPCO's Energy Waste Reduction ("EWR") program has yielded the intended goal of reducing volumes every year.

Q. Does UPPCO expect this long-term trend to continue?

A. Yes, UPPCO forecasts a continued decline of approximately 0.8% a year as discussed by Witness Stocking.

Q. What changes to overall rates have occurred since 2016?

A. Since 2016, UPPCO has significantly reduced purchased power costs, reduced EWR program costs, added a surcharge related to the Low-Income Energy

Assistance Fund (LIEAF) and has implemented significant savings stemming from the Tax Cuts and Jobs Act of 2017, among other changes.

Q. What was the net effect of these changes since 2016?

A. The net effect of these changes and others has resulted in a reduction of total operating expenses of over $17 million since the previous rate case in 2016. Due to the mechanics of these changes, some larger usage customers have experienced significant reductions.

Q. Please explain the changes related to the TCJA?

A. UPPCO is required to file a rate case or other filing to refund the excess deferred taxes by October 1, 2018. Within current rates, UPPCO is reflecting savings of $3.32 million annually for customers because of the TCJA Credit A filing. Within this case, UPPCO is proposing to pass through approximately $0.94 million in excess deferred taxes as supported by Company Witness Kates.

Q. Please explain the need to recover costs for investment in company infrastructure?

A. Since 2016, UPPCO is projecting an increase in rate base of approximately 15% (not including the Escanaba Hydro's accounting change). This is primarily driven by investment in core facilities to improve customer service, reliability and safety. This also includes the AMI Project which began in 2018 and is scheduled to be completed in 2019. This is described in detail by Company Witness Brynick.

Q. What is UPPCO's request concerning the Escanaba River Hydrofacilities?

A. UPPCO currently owns three MPSC regulated Hydroelectric Plants that exclusively serve a large customer under a special contract, approved by the

MPSC. While these assets are owned by the utility, they have not been included in utility rate base reporting to the MPSC. In addition, the special contract and MPSC Order related to these units were originally executed prior to 2008 PA 295 ("Act 295"). Act 295 added renewable energy requirements to utilities in the State, which are not addressed in the prior MPSC order. With changes in the law with respect to renewable energy requirements, as well as the requirements to an Integrated Resource Plan ("IRP") arising from 2016 PA 341, UPPCO determined it would be to proper to represent all accounting for these units as rate base in reports and proceedings with the MPSC. This would facilitate accounting for the renewable energy credits to be realized by the utility to the benefit of its customers.

Q. What is the effect of this change on the proposed rates by UPPCO?

A. Zero. As part of this accounting change, UPPCO has included all expenses, plant, and incremental revenue in this change. In addition, UPPCO has included a revenue adjustment to account for the current low rates this large customer currently receives.

Q. What other effects does this change have?

A. As evidenced in the Order approving UPPCO's Biennial Renewable Energy Plan (Case No. U-18235), UPPCO intends to utilize the renewable energy credits for these units to meet the utility requirements. This change also streamlines internal accounting.

Q. Please describe UPPCO's AMI solution.

A. UPPCO's AMI solution, which is focused on implementing foundational smart meter technology that seeks to (1) provide AMI meters (i.e., "smart meters") capable of transmitting and receiving data through the replacement of UPPCO's existing analog/digital meters for all residential and small commercial customers; (2) through use of a Radio Frequency ("RF") mesh communications network, allow meters and other devices to route data through secure wireless networking technologies; (3) provide system integration to support the use of data for billing and key operational uses, such as improved outage management, and (4) in a subsequent project, deliver a customer interface / web portal.

Many of the direct operational benefits will be related to meter reading automation, operational efficiencies in field and meter services, reduction in unaccounted for energy, operational efficiencies in billing and customer care, and improved outage management efficiency. UPPCO's AMI system is described in detail by Company Witness Brynick.

Q. What are the effects of the updated Cost of Service model?

A. UPPCO has completed an updated cost of service model, which is the first one since UPPCO was created as a stand-alone utility. This model is explained in detail by Company Witness Haehnel. The results of this model suggest:

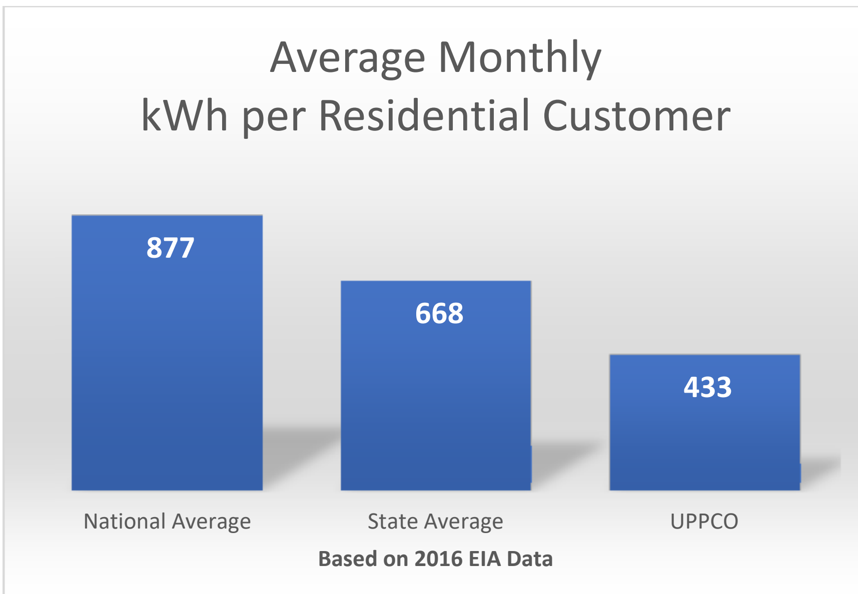
1. The changes in rates impact residential customers less than the commercial and industrial customer classes (de-skewing).

2. The changes in rates impact the volumetric component less than the fixed monthly charge.

This cost of service model is an important first step in establishing cost-based rates.

Q. How does UPPCO's average residential monthly usage compare to other companies?

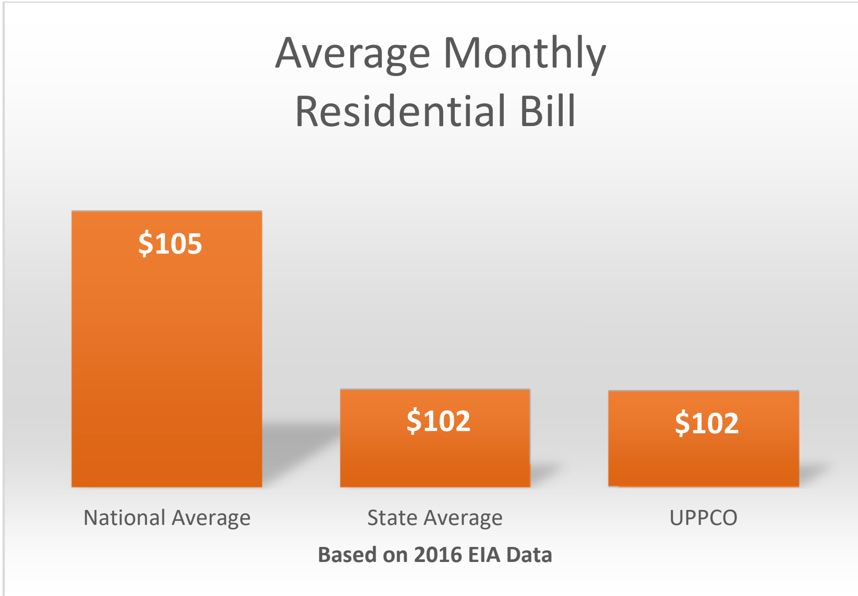
A. The following chart, sourced with data from the United Stated Energy Information Administration (EIA)[1] illustrates that UPPCO's typical annual electricity usage per customer is less than half of the national average. This is inherent in northern climates where air conditioning load and electric heat load is minimized.



Q. Although usage is low, how does UPPCO's revenue per residential customer compare to other companies?

A. The following chart, also sourced with data from the United Stated Energy Information Administration, illustrates that UPPCO's average revenue per residential customer is on par with other utilities in the state and is below the national average.

[1] https://www.eia.gov/electricity/data/eia861/zip/f8612016.zip



Q. How does UPPCO's low usage affect ratemaking?

A. Since UPPCO has very low customer usage, when the fixed costs of the business are recovered on a volumetric basis, a higher factor is needed to achieve the same amount of recovery as other companies with higher usage. As such, UPPCO customer base is better suited to recover all or most of the fixed costs in a fixed charge vs. a volumetric charge.

Q. What monthly fixed charge is UPPCO proposing for residential customers?

A. UPPCO is proposing a monthly fixed charge of $25 for residential customers. This is discussed in detail by Witness Stocking. By having a $25 monthly charge, the following will be accomplished:

1. This helps keep the volumetric charge lower.
2. This reduces the overall bill for full time residences and will increase the bill for seasonal residences.
3. This charge is consistent with other utilities in the Upper Peninsula who have low customer usage like UPPCO.

Q. Why does UPPCO feel a 10.5% ROE is appropriate?

A. In principle, an ROE should be set at a fair level appropriate to attract investors for a utility. This is discussed in detail by Witness McKenzie. When setting an ROE, the following principles apply:

1. Given the same return on investment, an investor will invest in the least risk investment.

2. To attract investors to a higher risk investment, the investment must have the potential for a higher rate of return.

3. As such, a riskier utility should be allowed the opportunity to earn a higher ROE.

4. The higher risk profile a utility has, the higher its approved ROE needs to be to attract investment.

5. Smaller companies have more risk than larger companies.

6. Less diversified companies have more risk than highly diversified companies.

7. Companies in economically burdened areas have higher risk.

Q. Why does UPPCO feel a 10.5% ROE is appropriate?

A. Witness McKenzie has recommended an ROE of 10.5% for UPPCO based on a comparison to other companies of a similar risk profile.

Q. Please describe UPPCO's $26 million revenue offset (credit) and describe the importance of UPPCO's proposed update?

A. In MPSC Case No. U-17564, the Company agreed to a $26 million revenue credit which began when rates were set in the 2016 Rate Case. To continue to meet the requirement of providing the $26 million credit to customers, the

Company has calculated the amount of benefit the customers have received since the credit began and has adjusted the amount on a go-forward basis. This ensures that customers will realize the entire $26 million credit. This is discussed in detail by Witness Haehnel.

Q. What improvements have been made to improve reliability for customers?

A. UPPCO recently completed the four-year accelerated tree trimming program in 2017. This puts UPPCO back onto a normal six-year schedule, which is considered an industry standard for a utility of our rural nature. UPPCO has met this commitment and as discussed by Witness Moyle's testimony moving to a 6-year schedule is reasonable. Now that tree trimming is back on a routine schedule, UPPCO is focusing on system hardening and infrastructure investments to achieve higher reliability metrics.

Q. Does that 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.	)	Case No. U-20276
______________________________________	)	

DIRECT TESTIMONY AND EXHIBITS OF

NICHOLAS E. KATES

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

September 21, 2018

QUALIFICATIONS

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

A. My name is Nicholas E. Kates. My business address is 1002 Harbor Hills Drive, Marquette, MI 49855. I am the Chief Financial Officer ("CFO") 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 a Master of Business Administration from Millikin University. I began my career in public accounting in 1991 and have helped various accounting and finance roles in manufacturing and chemical organizations, culmination with my role and Business Unit Chief Financial Officer of DSM Functional Materials prior to joining UPPCO as Chief Financial Officer in 2015.

Q. Have you previously testified in any regulatory proceedings?

A. No.

PURPOSE OF TESTIMONY

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

A. UPPCO has used a historical test year ending December 31, 2017.

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

A. UPPCO has used a projected test year ending December 31, 2019.

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

A. The purpose of my testimony is to present UPPCO's 2017 historical test year revenue requirement and UPPCO's 2019 projected test year revenue requirement. I will also discuss UPPCO's information technology capital expenditures, along with compensation structure and benefit plans.

REVENUE REQUIREMENT EXHIBITS

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. For the historical 2017 test year, I am sponsoring the following exhibits:

1. Exhibit A-1, Schedules A1 through A2,
2. Exhibit A-2, Schedules B1 through B4,
3. Exhibit A-3, Schedules C1 through C11, and
4. Exhibit A-4, Schedules D1 through D5.

For the projected 2019 test year, I am sponsoring the following exhibits:

5. Exhibit A-11, Schedules A1 through A2,
5. Exhibit A-12, Schedules B1 through B5,
6. Exhibit A-13, Schedules C1 through C11, and
7. Exhibit A-14, Schedules D1 through D5

Q. What other exhibits are your sponsoring?

A. I am sponsoring the following other supporting exhibits.

8. Exhibit A-17, 2019 Financial Summary
9. Exhibit A-18, 2019 Forecast Adjustments
10. Exhibit A-19, FERC 926 Summary
11. Exhibit A-20, AFUDC Calculation
12. Exhibit A-21, 2019 LIBOR
13. Exhibit A-22, Q2-2018 CPI
14. Exhibit A-23, Salary & Wage Adjustment
15. Exhibit A-24, Uncollectible Accounts (Bad Debt Expense)
16. Exhibits A-25.1, Willis Towers & Watson Report – Pension & OPEB, Part I
17. Exhibits A-25.2, Willis Towers & Watson Report – Pension & OPEB, Part II
18. Exhibits A-25.3, Willis Towers & Watson Report – Pension & OPEB, Part III
19. Exhibit A-26, UPPCO Information Technology (IT) CAPEX

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.

A. Schedule A1 of Exhibit A-1 calculates UPPCO's 2017 historical test year revenue deficiency 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.

A. Schedule A2 of Exhibit A-1 calculates UPPCO's historical financial metrics on both a financial basis and ratemaking basis from 2013 through 2017.

Q. Please describe Schedule B1 of Exhibit A-2.

A. Schedule B1 of Exhibit A-2 calculates UPPCO's 2017 historical test year rate base.

Q. Please describe Schedule B2 of Exhibit A-2.

A. Schedule B2 of Exhibit A-2 calculates UPPCO's 2017 historical test year utility plant.

Q. Please describe Schedule B3 of Exhibit A-2.

A. Schedule B3 of Exhibit A-2 depicts UPPCO's 2017 historical test year accumulated provision for depreciation.

Q. Please describe Schedule B4 of Exhibit A-2.

A. Schedule B4 of Exhibit A-2 calculates UPPCO's 2017 historical test year working capital.

Q. Please describe Schedule C1 of Exhibit A-3.

A. Page 1 of Schedule C1 of Exhibit A-3 calculates UPPCO's 2017 historical test year adjusted net operating income. Page 2 of Schedule C1 of Exhibit A-3 calculates UPPCO's 2017 historical test year interest synchronization.

Q. Please describe Schedule C2 of Exhibit A-3.

A. Schedule C2 of Exhibit A-3 calculates UPPCO's 2017 historical test year gross revenue conversion factor.

Q. Please describe Schedule C3 of Exhibit A-3.

A. Schedule C3 of Exhibit A-3 calculates UPPCO’s 2017 historical test year total revenue.

Q. Please describe Schedule C4 of Exhibit A-3.

A. Schedule C4 of Exhibit A-3 calculates UPPCO’s 2017 historical test year total fuel and purchased power cost.

Q. Please describe Schedule C5 of Exhibit A-3.

A. Schedule C5 of Exhibit A-3 calculates UPPCO’s 2017 historical test year total operation and maintenance (“O&M”) expense.

Q. Please describe Schedule C6 of Exhibit A-3.

A. Schedule C6 of Exhibit A-3 depicts UPPCO’s 2017 historical test year total depreciation and amortization expense.

Q. Please describe Schedule C7 of Exhibit A-3.

A. Schedule C7 of Exhibit A-3 calculates UPPCO’s 2017 historical test year total for taxes other than income taxes.

Q. Please describe Schedule C8 of Exhibit A-3.

A. Schedule C8 of Exhibit A-3 depicts UPPCO’s 2017 historical test year federal income taxes.

Q. Please describe Schedule C9 of Exhibit A-3.

A. Schedule C9 of Exhibit A-3 depicts UPPCO’s 2017 historical test year state income taxes.

Q. Please describe Schedule C10 of Exhibit A-3.

A. Schedule C10 of Exhibit A-3 depicts UPPCO's 2017 historical test year local taxes.

Q. Please describe Schedule C11 of Exhibit A-3.

A. Schedule C11 of Exhibit A-3 depicts UPPCO's 2017 historical test year Allowance for Funds Used During Construction ("AFUDC").

Q. Please describe Schedule D1 of Exhibit A-4.

A. Schedule D1 of Exhibit A-4 depicts UPPCO's 2017 historical test year rate of return summary and capital structure.

Q. Please describe Schedule D2 of Exhibit A-4.

A. Schedule D2 of Exhibit A-4 depicts UPPCO's 2017 historical test year cost of long-term debt.

Q. Please describe Schedule D3 of Exhibit A-4.

A. Schedule D3 of Exhibit A-4 depicts UPPCO's 2017 historical test year cost of short-term debt.

Q. Please describe Schedule D4 of Exhibit A-4.

A. Schedule D4 of Exhibit A-4 depicts UPPCO's 2017 historical test year cost of preferred stock.

Q. Please describe Schedule D5 of Exhibit A-4.

A. Schedule D5 of Exhibit A-4 depicts UPPCO's 2017 historical test year cost of common shareholder's equity.

Q. Please describe Schedule A1 of Exhibit A-11.

A. Schedule A1 of Exhibit A-11 calculates UPPCO's 2019 projected test year revenue deficiency 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-11.

A. Schedule A2 of Exhibit A-11 calculates UPPCO's 2019 projected test year financial metrics absent rate relief and with full rate relief.

Q. Please describe Schedule B1 of Exhibit A-12.

A. Schedule B1 of Exhibit A-12 calculates UPPCO's 2019 projected 13-month average test year rate base.

Q. Please describe Schedule B2 of Exhibit A-12.

A. Schedule B2 of Exhibit A-12 calculates UPPCO's 2019 projected 13-month average test year utility plant.

Q. Please describe Schedule B3 of Exhibit A-12.

A. Schedule B3 of Exhibit A-12 depicts UPPCO's 2019 projected 13-month average test year accumulated provision for depreciation.

Q. Please describe Schedule B4 of Exhibit A-12.

A. Schedule B4 of Exhibit A-12 calculates UPPCO's 2019 projected 13-month average test year working capital.

Q. Please describe Schedules B5, B5.1, B5.4, B5.5 and B5.6 of Exhibit A-12.

A. Schedule B5 of Exhibit A-12 provides a summary of the Company's actual and projected capital expenditures by business line (i.e., distribution, substation, generation, and corporate) for each year from 2016 through 2019.

Schedule B5.1 of Exhibit A-12 provides a summary of the Company's actual and projected capital expenditures for power generation from 2017 through 2019.

Schedule B5.4 of Exhibit A-12 provides a summary of the Company's actual and projected expenditures for distribution and substation from 2017 through 2019.

Schedule B5.5 of Exhibit A-12 provides a summary of the Company's projected expenditures related to its Advanced Metering Infrastructure ("AMI") project for 2018 and 2019.

Schedule B5.6 of Exhibit A-12 provides a summary of the Company's actual and projected capital expenditures for corporate from 2017 through 2019.

Q. Please describe Schedule C1 of Exhibit A-13.

A. Schedule C1 of Exhibit A-13 calculates UPPCO's 2019 projected test year adjusted net operating income.

Q. Please describe Schedule C2 of Exhibit A-13.

A. Schedule C2 of Exhibit A-13 calculates UPPCO's 2019 projected test year gross revenue conversion factor.

Q. Please describe Schedule C3 of Exhibit A-13.

A. Schedule C3 of Exhibit A-13 calculates UPPCO's 2019 projected test year total revenue.

Q. Please describe Schedule C4 of Exhibit A-13.

A. Schedule C4 of Exhibit A-13 calculates UPPCO's 2019 projected test year total fuel and purchased power cost.

Q. Please describe Schedule C5 of Exhibit A-13.

A. Schedule C5 of Exhibit A-13 calculates UPPCO's 2019 projected test year total O&M expense.

Q. Please describe Schedule C6 of Exhibit A-13.

A. Schedule C6 of Exhibit A-13 depicts UPPCO's 2019 projected test year total depreciation and amortization expense.

Q. Please describe Schedule C7 of Exhibit A-13.

A. Schedule C7 of Exhibit A-13 calculates UPPCO's 2019 projected test year total for taxes other than income taxes.

Q. Please describe Schedule C8 of Exhibit A-13.

A. Schedule C8 of Exhibit A-13 depicts UPPCO's 2019 projected test year federal income taxes.

Q. Please describe Schedule C9 of Exhibit A-13.

A. Schedule C9 of Exhibit A-13 depicts UPPCO's 2019 projected test year state income taxes.

Q. Please describe Schedule C10 of Exhibit A-13.

A. Schedule C10 of Exhibit A-13 depicts UPPCO's 2019 projected test year local taxes.

Q. Please describe Schedule C11 of Exhibit A-13.

A. Schedule C11 of Exhibit A-13 depicts UPPCO's 2019 projected test year AFUDC.

Q. Please describe Schedule D1 of Exhibit A-14.

A. Schedule D1 of Exhibit A-14 depicts UPPCO's 2019 projected test year rate of return summary and capital structure.

Q. Please describe Schedule D2 of Exhibit A-14.

A. Schedule D2 of Exhibit A-14 depicts UPPCO's 2019 projected test year cost of long-term debt.

Q. Please describe Schedule D3 of Exhibit A-14.

A. Schedule D3 of Exhibit A-14 depicts UPPCO's 2019 projected test year cost of short-term debt.

Q. Please describe Schedule D4 of Exhibit A-14.

A. Schedule D4 of Exhibit A-14 depicts UPPCO's 2019 projected test year cost of preferred stock.

Q. Please describe Schedule D5 of Exhibit A-14.

A. Schedule D5 of Exhibit A-14 depicts UPPCO's 2019 projected test year cost of common shareholder's equity.

FORECAST METHODOLOGY

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

A. While 2008 Public Act 286 allows for projected future test periods in setting utility rates, 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.

Q. Please describe the major components of UPPCO's forecast that informed the 2019 projected test year.

A. The major components are as follows:

1. Sales and demand forecast. Based on historical data, UPPCO uses 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 Stocking is presenting UPPCO's sales forecast utilized in the projected 2019 test year. The 2019 projected test year sales and demand forecasts not only are key drivers in projecting 2019 operating revenues, but they also serve as inputs into the 2019 projected test year Cost of Service Study ("COSS") supported by Company Witness Haehnel, and the development of rates through rate design, again, supported by Company Witness Stocking.
2. Power supply forecast. For purposes of establishing jurisdictional revenue requirements, UPPCO has utilized its most recently approved power supply costs as represented in MPSC Case No. U-18406. The Power Supply Cost Recovery ("PSCR") factor used to calculate present revenues with present rates in this general rate case proceeding is presented such that PSCR costs equal PSCR revenues, resulting in a one-for-one recovery of PSCR costs.

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 2019 operating revenues are evidenced on line 2 of Schedule C1 of Exhibit A-13, whereby present rates are applied to 2019 projected test year sales and demand. For the derivation of 2019 projected wholesale revenues, UPPCO assumed wholesale revenues equivalent to that of the 2017 historical test year.
4. Operations and maintenance forecast. Operation and maintenance forecasts, excluding energy 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, non-PSCR transmission, customer accounts, customer service and administrative and general expenses. For these costs, UPPCO first applied any known and measurable adjustments to the 2017 historical test year, then escalated these 2017 historical test year costs by an inflation factor to derive the 2019 projected test year values (based on a 2017 inflation-adjusted historical test year), and then made certain forecast adjustments to the 2019 projected test year based on other budgetary and/or known information. These forecast adjustments are identified in Exhibit A-18, 2019 Forecast Adjustments.
5. Capital expenditure forecast. The capital expenditure forecast is developed by various UPPCO 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 2019 test year capital expenditure forecast for the distribution, substation, generation, fleet and

facilities investments is provided by Company Witness Moyle, for the AMI investment is provided by Company Witnesses Brynick and Haehnel, and for information technology investments is provided by myself later in my testimony.

6. Financing plan. In determining the company's financing program, consideration is given to interest coverage and other regulatory restrictions, timing of requirements, availability of equity capital, and corporate objective such as credit metrics, capital structure and short-term debt limitations.
7. Special adjustments.
    a. Escanaba Hydroelectric Facilities ("Escanaba Hydro's"). As Company Witness Haehnel describes in his testimony, UPPCO is representing the Escanaba Hydro's and their associated costs in the 2019 projected test year. The inclusion of these facilities is structured in a manner such that it ensures customers are held harmless from a cost perspective, yet still positioned to receive long-term value from the renewable attributes.

2019 PROJECTED TEST YEAR REVENUE DEFICIENCY

Q. Please explain Schedule A-1 of Exhibit A-11.

A. Schedule A-1 of Exhibit A-11 calculates UPPCO's projected 2019 test year revenue deficiency based on its rate base, adjusted net operating income, rate of return and revenue conversion factor. This schedule indicates that the 2019 total company revenue deficiency is $10,509,690 and the 2019 Michigan retail revenue deficiency is $9,982,604. As shown on the schedule, the component parts are taken from the various sources indexed to the left of each value.

Q. Please describe the revenue offset on line 18 of Schedule A-1 of Exhibit A-11.

A. On June 6, 2014, as part of the Settlement Agreement approved by the Commission in Case No. U-17564 regarding the purchase of UPPCO from Integrys Energy Group, Inc., UPPCO agreed to provide a revenue offset for customers valued at $26 million to be spread over six consecutive years with an effective date of when rates would go into effect in next base rate case. This planned $26 million revenue offset commenced on September 23, 2016, which was the effective date of the Company's last rate implementation pursuant Case No. U-17895. The revenue offset presented on line 18 of Schedule A-1 of Exhibit A-11 has been updated to $2,584,802 and is supported by testimony provided by Company Witness Haehnel.

Q. Please describe the revenue credit on lines 20 and 22 of Schedule A-1 of Exhibit A-11.

A. In the Order approving rates in Case No. U-17895, the Commission found that UPPCO should do the following:

> (1) UPPCO shall use a test year pension expense of $1.7 million, and shall record any future pension expense below that amount, on a yearly basis, as a regulatory liability; (2) UPPCO shall treat the total $59 million related to pension expense as a regulatory asset, and shall receive a return of and on that amount; and (3) UPPCO shall implement an additional $390,000 revenue credit beginning with the 2016 test year through December 31, 2021.

With a test year pension expense of $1,700,000 million approved in UPPCO's last rate case, UPPCO projects an accrued regulatory liability of $2,083,690 by July of 2019 because UPPCO's actual pension expense has been less than the assumed prior rate case test year value of $1,700,000 million in both 2016 and 2017. UPPCO is proposing to eliminate the pension tracker and associated pension-related revenue credits, as described immediately above. UPPCO has eliminated these revenue credit offsets because UPPCO now has historical costs regarding pension expense. In the 2017 historical test year, these costs were $1,171,647. Further, UPPCO's 2019 projected expense is $883,068, which is $816,932 below what was approved in the last case. Commencing with an effective date coincident with the timing of a final order in this case, UPPCO will amortize this projected $2,083,690 regulatory liability over a forward-looking three-year period through a revenue credit valued at ($694,563) per year, as evidenced on line 22.

2019 PROJECTED TEST YEAR FINANCIAL METRICS

Q. Please explain Schedule A-2, pages 1 through 3, of Exhibit A-11.

A. Schedule A-2, page 1 of Exhibit A-11 develops financial metrics on a ratemaking basis for UPPCO's projected 2019 test year. Absent rate relief, UPPCO's earned rate of return on common equity would be 3.84%, as evidenced on line 14.

Schedule A-2, page 2 of Exhibit A-11 develops additional financial metrics on a ratemaking basis for UPPCO's projected 2019 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: 2.33
    b. With full rate relief: 5.01
2. EBITDA Interest Coverage Ratio, as evidenced on line 25.
    a. Absent rate relief: 4.50
    b. With full rate relief: 7.17
3. Funds Flow from Operations (FFO) Interest Coverage Ratio, as evidenced on line 35.
    a. Absent rate relief: 5.50

b. With full rate relief: 8.02

4. Overall Fixed Charge Coverage Ratio, as evidenced on line 42.

a. Absent rate relief: 2.15

b. With full rate relief: 4.14

Schedule A-2, page 3 of Exhibit A-11 develops additional financial metrics on a ratemaking basis for UPPCO's projected 2019 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: $262,582,586

f. With full rate relief: $262,582,586

2019 PROJECTED TEST YEAR RATE BASE

Q. Please explain Schedule B1 of Exhibit A-12.

A. Schedule B1 of Exhibit A-12 calculates UPPCO's 2019 projected test year rate base. The 2019 total company rate base is $281,736,440, and the 2019 Michigan retail rate base is $278,888,974 , 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-12.

A. Schedule B2 of Exhibit A-12 depicts UPPCO's 2019 projected test year utility plant. To arrive at the 2019 projected test year utility plant, the 2017 actual balance of utility plan was projected forward using UPPCO's projected 2018 and 2019 construction budgets. The 2019 total company utility plant is $381,332,731, and the 2019 Michigan retail utility plant is $376,955,742, as shown in line 13. All values shown are 13-month averages.

Q. Please explain Schedule B3 of Exhibit A-12.

A. Schedule B3 of Exhibit A-12 depicts UPPCO's 2019 projected test year accumulated provision for depreciation. To arrive at the 2019 projected test year accumulated provision for depreciation, the 2017 actual balance of accumulated provision for depreciation was projected forward using UPPCO's 2018, and 2019 construction budgets. The 2019 total company accumulated provision for depreciation is $148,844,112, and the 2019 Michigan retail accumulated provision for depreciation is $146,947,626 as shown on line 2. All values shown are 13-month averages.

Q. Please explain Schedule B4 of Exhibit A-12.

A. Schedule B4 of Exhibit A-12 calculates UPPCO's 2019 projected test year working capital. The 2019 total company working capital is $49,247,821, and the 2019 Michigan retail working capital is $48,880,858 as shown on line 38. All values shown are 13-month averages.

Q. Please explain Schedules B5, B5.1, B5.4, B5.5 and B5.6 of Exhibit A-12.

A. Schedule B5 of Exhibit A-12 provides a summary of the Company's actual and projected capital expenditures by business line (i.e., distribution, substation, generation, and corporate) for each year from 2016 through 2019. Actual 2016 and 2017 total capital expenditures totaled $31,946,191 and $19,243,027, respectively. Projected 2018 and 2019 total capital expenditures total 26,768,980 and 22,215,645.

Schedule B5.1 (Page 1) of Exhibit A-12 provides a summary of the Company's actual and projected capital expenditures for power generation from 2017 through 2019. Actual 2017 capital expenditures for power generation totaled $560,486. Projected 2018 and 2019 capital expenditures total $1,608,448 and $1,310,000. Company Witness Moyle provides supporting testimony regarding these capital expenditures.

Schedule B5.1 (Page 2) of Exhibit A-12 provides a summary of the Company's actual and projected capital expenditures for power generation by facility from 2017 through 2019. Actual 2017 capital expenditures for power generation totaled $560,486. Projected 2018 and 2019 capital expenditures total $1,608,448 and $1,310,000. Company Witness Moyle provides supporting testimony regarding these capital expenditures.

Schedule B5.4 (Page 1) of Exhibit A-12 provides a summary of the Company's actual and projected expenditures for distribution and substation from 2017 through 2019. Actual 2017 capital expenditures for distribution and substation totaled $10,208,073. Projected 2018 and 2019 capital expenditures for distribution and substation total

$9,174,364 and $10,360,578. Company Witness Moyle provides supporting testimony regarding these capital expenditures.

Schedule B5.5 of Exhibit A-12 provides a summary of the Company's projected expenditures related to its AMI project for 2018 and 2019. Projected 2018 and 2019 capital expenditures for the AMI project total $8,702,990 and $6,933,470. Company Witnesses Brynick & Haehnel provide supporting testimony regarding this project and its associated costs.

Schedule B5.6 of Exhibit A-12 provides a summary of the Company's actual and projected capital expenditures for corporate from 2017 through 2019. Included within corporate capital expenditures are investments related to information technology, fleet, facilities and special projects. Actual 2017 capital expenditures for corporate totaled $8,474,468. Projected 2018 and 2019 capital expenditures for corporate total $15,986,168 and $10,545,067, respectively. Company Witnesses Brynick & Haehnel provide testimony supporting the AMI portion of Special Projects, as depicted on line 5. Company Witness Moyle provides supporting testimony regarding fleet and facilities capital expenditures.

Q. Please identify and describe any additional supporting exhibits related to UPPCO's 2018 through 2019 projected capital expenditures for information technology.

A. Exhibit A-26, UPPCO Information Technology (IT) CAPEX, identifies projects greater than $100,000 for the 2018 and 2019 projected test year. As demonstrated on line 13 of this exhibit, UPPCO's 2018 capital spend is estimated at $3,131,000, and UPPCO's 2019 projected capital spend is $983,000.

2019 PROJECTED TEST YEAR OPERATING INCOME

Q. Please explain Schedule C1 of Exhibit A-13.

A. Schedule C1 of Exhibit A-13 calculates UPPCO's 2019 projected test year adjusted net operating income. The 2019 total company adjusted net operating income is $11,086,417 and the 2019 Michigan retail adjusted net operating income is $11,262,295 as shown on Line 22. The interest synchronization calculation is shown on page 2 of Schedule C1 of Exhibit A-13.

Q. Please explain Schedule C2 of Exhibit A-13.

A. Schedule C2 of Exhibit A-13 calculates UPPCO's 2019 projected test year gross revenue conversion factor. The 2019 gross revenue conversion factor is 1.3466.

Q. Please explain Schedule C3 of Exhibit A-13.

A. Schedule C3 of Exhibit A-3 calculates UPPCO's 2019 projected test year total revenue. The 2019 total company revenues are $103,661,998, and the 2019 Michigan retail total revenue is $102,819,014 as shown on line 6.

Q. Please explain Schedule C4 of Exhibit A-13.

A. Schedule C4 of Exhibit A-13 calculates UPPCO's 2019 projected test year total fuel and purchased power cost of $34,364,517 as shown on line 6. This can be compared to fuel and purchased power costs of $48,284,554 approved in UPPCO's last rate case, Case No. U-17895. The reduction in projected fuel and purchased power costs is mainly due to UPPCO's effective management of capacity and energy contracts, including the termination of certain legacy purchased power agreements.

Q. Please explain Schedule C5 of Exhibit A-13.

A. Schedule C5 of Exhibit A-13 calculates UPPCO's 2019 projected test year total O&M expense, exclusive of fuel and purchased power. The 2019 total company O&M expense is $38,737,149 and the 2019 Michigan retail total O&M expense is $38,280,079 as shown on line 11.

Q. Please explain Schedule C6 of Exhibit A-13.

A. Schedule C6 of Exhibit A-13 depicts UPPCO's 2019 projected test year total depreciation and amortization expense. The 2019 total company total depreciation and amortization expense is $11,169,782, and the 2019 Michigan retail total depreciation and amortization expense is $11,015,149 as shown on line 6. Depreciation on line 3 was calculated based upon projected plant balances and closings for the 2019 test year, using the depreciation rates approved in Case No. U-15989.

Q. Has UPPCO made a forecast adjustment to depreciation and amortization expense due to its concurrent depreciation case in Case No. U-18467? Please explain.

A. Yes. Pursuant to the order dated July 31, 2018 in Case No. U-18238, UPPCO has presented its full depreciation case request of a depreciation and amortization expense decrease of $1,808,795.

Q. Please explain Schedule C7 of Exhibit A-13.

A. Schedule C7 of Exhibit A-13 depicts UPPCO's 2019 projected test total for taxes other than income taxes. The 2019 total company total taxes other than income taxes is

$6,808,596, and the 2019 Michigan retail total taxes other than income taxes is $6,730,509 as shown on line 29.

Q. Please explain Schedule C8 of Exhibit A-13.

A. Schedule C8 of Exhibit A-13 depicts UPPCO's 2019 projected test year federal income taxes. The 2019 total company federal income taxes are $588,880, and the 2017 Michigan retail income taxes are $567,880 as shown on line 15.

Q. Please explain Schedule C9 of Exhibit A-13.

A. Schedule C9 of Exhibit A-13 depicts UPPCO's 2019 projected test year state income taxes. The 2019 total company state income taxes are $338,923 and the 2019 Michigan retail state income taxes are $333,743 as shown on line 15.

Q. Please explain Schedule C10 of Exhibit A-13.

A. Schedule C10 of Exhibit A-13 depicts UPPCO's 2019 projected test year local taxes. The 2019 total company local taxes are $0, as shown in the exhibit.

Q. Please explain Schedule C11 of Exhibit A-13.

A. Schedule C11 of Exhibit A-13 depicts UPPCO's 2019 projected test year AFUDC. The 2019 total company AFUDC is $257,800 and the 2019 Michigan retail AFUDC is $255,017 as shown on line 5. Exhibit A-20, AFUDC Calculation, provides supporting evidence of this calculation.

2019 PROJECTED TEST YEAR CAPITAL STRUCTURE

Q. Please explain Schedules D1 through D5 of Exhibit A-14.

A. In general, Schedules D1 through D5 of Exhibit A-14 support and calculate UPPCO's capital structure, cost of capital, and required rate of return for the 2019 projected test year.

Schedule D1 develops UPPCO's 2019 projected test year overall rate of return of 7.57%, as shown on line 22, based on UPPCO's 13-month average capital structure, and a proposed 10.5% ROE.

Schedule D2 develops UPPCO's 2019 projected test year cost of long-term debt of 4.4639%, based on a 13-month average, as shown on line 24.

Schedule D3 develops UPPCO's 2019 projected test year cost of short-term debt of 4.375%, based on a 13-month average, as shown on line 14.

Schedule D4 indicates that UPPCO has no preferred equity outstanding, as shown on line 2.

Schedule D5 develops UPPCO's 13-month average balance of Adjusted Common Equity of $154,382,586 for the 2019 projected test year, as shown on line 16. UPPCO requests a 10.5% ROE for the 2019 projected test year in this general rate case proceeding, as supported by Company Witness Adrien McKenzie's direct testimony and exhibits.

Q. How were interest rates on short-term debt forecasted?

A. Short-term debt interest rates were derived based on the forecasted 3-month London Interbank Offered Rate ("LIBOR") plus our required 137.5 basis point premium with a Ba1 rating from Moody's. As evidenced in Exhibit A-21, 2019 LIBOR, per *Blue Chip Financial Forecasts*, dated June 1, 2018, the consensus forecast quarterly averages for

2019-Q1 through 2019-Q3 regarding the 3-month LIBOR rate are 2.8% (Q1), 3.0% (Q2) and 3.1% (Q3) for a forecasted simple average of 3.0%. Based on this calculated 3.0% average for the forecasted 2019 3-month LIBOR rate, as well as the required 137.5 basis point premium on top of the 3.0% 2019 forecasted LIBOR, UPPCO's assumed short-term debt interest rate for the 2019 projected test year is 4.375%.

2019 PROJECTED TEST YEAR FORECAST ADJUSTMENTS

Q. Please describe how the Company's projected 2019 forecast is developed.

A. UPPCO's methodology utilized a historical 2017 test year upon which it made certain known and measurable adjustments. UPPCO then escalated the historical 2017 costs by inflation to derive projected 2019 values. UPPCO subsequently made certain forecast adjustments to the projected 2019 test year to derive it's projected 2019 values.

Q. What inflation assumption did UPPCO utilize when escalating the historical 2017 values to the projected 2019 values and why is this rate reasonable?

A. UPPCO used an inflation rate of 2.66% which is comprised of the average value of the United States Treasury Yield Curve Rates for a 10-year[1] note on the following three dates: December 29, 2017 [2.40%], March 29, 2018 [2.74%], and June 29, 2018 [2.85%]. Because UPPCO is applying this escalation factor upon historical 2017 values, UPPCO believes this approach to be a reasonable approach to developing an inflation factor for 2018 and 2019. As further validation of UPPCO's 2.66% inflation rate

[1] https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

adjustment, please find Exhibit A-22, Q2-2018 CPI, which illustrates that the Consumer Price Index ("CPI") averaged 2.73%[2] for the most recent second quarter of 2018.

Q. How does UPPCO present the 2019 forecast adjustments?

A. Please find Exhibit A-18, 2019 Forecast Adjustments. Starting on line 2, column D, UPPCO presents the value of the forecast adjustment which represents the amount by which UPPCO is changing its inflation-adjusted 2017 historical test year values. Separately, Company Witness Haehnel supports the 2019 projected test year forecast adjustments related to the Escanaba Hydro's.

Q. Please summarize UPPCO's forecast adjustments to the 2019 projected test year?

A. As evidenced in Exhibit A-18, 2019 Forecast Adjustments, UPPCO identifies its 2019 projected test year income statement adjustments. As listed in detail in the exhibit on line 17, these 15 income statement adjustments sum to a total decrease of $4,556,567. The one balance sheet adjustment listed on line 20 represents a change to accumulated depreciation reserve of $1,808,795 in alignment with UPPCO's concurrent depreciation case U-18467.

Q. Please explain 2019 Forecast Adjustment 1 as evidenced in Exhibit A-18, 2019 Forecast Adjustments.

A. UPPCO is transitioning to a 6-year cycle line clearance program after a 4-year aggressive "make-up" line clearance schedule as ordered in Case No. U-17274. In 2017, UPPCO spent $3,257,207 to trim 475 miles of line. In 2019, UPPCO is proposing to spend

[2] https://data.bls.gov/timeseries/CUUR0000SA0?output_view=pct_12mths

$2,330,500 in order trim 401 miles of line. Since the terms of Case No. U-17274 have expired, UPPCO proposes establishing its line clearance program moving to a new 6-year cycle. When compared to 2017 actual expenditures escalated with two years of inflation, UPPCO's 2019 projected test year line clearance expenditures will result in a reduction of ($926,707). Company Witness Moyle provides further supporting testimony.

Q. Please explain 2019 Forecast Adjustment 2 as evidenced in Exhibit A-18, 2019 Forecast Adjustments.

A. UPPCO has calculated the incremental wage increase for the production operational area to be $7,701. This calculation is further supported by Exhibit A-23, Salary & Wage Adjustment, on line 20. Because UPPCO increased 2017 costs by the 2.66% inflation factor and knowing that the 2019 projected wage adjustment for union workers is 3.5%, UPPCO applied the incremental 0.84% to FERC 544 to account for this adjustment.

Q. Please explain 2019 Forecast Adjustment 3 as evidenced in Exhibit A-18, 2019 Forecast Adjustments.

A. UPPCO has calculated the incremental wage increase for the distribution operational area to be $37,438. This calculation is further supported by Exhibit A-23, Salary & Wage Adjustment, line 21. Because UPPCO increased 2017 costs by the 2.66% inflation factor and knowing that the 2019 projected wage adjustment for union workers is 3.5%, UPPCO applied the incremental 0.84% to FERC 582 to account for this adjustment.

Q. Please explain 2019 Forecast Adjustment 4 as evidenced in Exhibit A-18, 2019 Forecast Adjustments.

A. UPPCO has calculated the incremental wage increase for the customer accounts operational area to be $11,212. This calculation is further supported by Exhibit A-23, Salary & Wage Adjustment, line 22. Because UPPCO increased 2017 costs by the 2.66% inflation factor and knowing that the 2019 projected wage adjustment for union workers is 3.5%, UPPCO applied the incremental 0.84% to FERC 903 to account for this adjustment.

Q. Please explain 2019 Forecast Adjustment 5 as evidenced in Exhibit A-18, 2019 Forecast Adjustments.

A. UPPCO is proposing to stop charging customers a credit card fee to make it easier and more convenient for customers to pay their bills. UPPCO estimates the cost of this service to be $129,012 in 2019, which will represent an incremental unrecovered cost from 2017 inflation-adjusted historical test year costs. The derivation of this value assumes a $3.49995 per transaction fee and an assumed 36,861 transactions. UPPCO is proposing to stop charging customers a credit card fee because the Company believes that by removing this obstacle, customers will pay their bills faster thereby reducing UPPCO's accounts receivables, arrearage and potential uncollectible (bad debt) expenses. Currently, UPPCO has approximately 30,722 annual credit card transactions and, in this projection, is assuming an approximate 20% increase in transaction volume in the 2019 projected test year.

Q. Please explain 2019 Forecast Adjustment 6 as evidenced in Exhibit A-18, 2019 Forecast Adjustments.

A. UPPCO has calculated the uncollectible accounts expense (FERC 904) based on a methodology approved in Case No. U-17895 which utilized a three-year average of net write-offs applied to revenues. In 2017, UPPCO's total uncollectible accounts expense was $2,198,285. As evidenced in Exhibit A-24, Uncollectible Accounts (Bad Debt Expense), the three-year inflation-adjusted average for 2015 through 2017 is $1,175,522. When compared to 2017 actual expenditures escalated at two years of inflation, UPPCO's 2019 projected test year uncollectible accounts (bad debt) expenditures results in a reduction of $1,022,763 from the 2017 inflation-adjusted value.

Q. Is it just and reasonable to establish a projected test year expense based on a historical three-year average?

A. Yes. By including the recent historic three-year average from 2015 through 2017, UPPCO is equitably reflecting the risks of uncollectible accounts for UPPCO's typical operations over a forward-looking span of time. UPPCO's position is that the approved level of bad debt expense does not recover customer-specific bad debts on a retroactive basis; however, an appropriate level of assumed bad debt expense mitigates future bad debt expense that UPPCO will likely incur over a forward-looking period.

Q. Please explain 2019 Forecast Adjustment 7 as evidenced in Exhibit A-18, 2019 Forecast Adjustments.

A. As represented in FERC 908 (Customer Assistance Expenses), the three primary components of costs that make up the 2019 forecast adjustment are energy conservation measures, low-income assistance funding and key account representative support costs for medium and large customers. First, in Case No. U-18265 regarding UPPCO's 2018

& 2019 Energy Waste Reduction ("EWR") Plan, the Commission approved a settlement agreement whereby the Company's approved plan and budget for 2019 is $1,612,452. Second, pursuant to Case No. U-17377, UPPCO is presently participating in the Low-Income Energy Assistance Fund ("LIEAF") and thereby incurring an incremental $572,363 to support this valuable program for customers at the per meter rate of $0.93. Lastly, associated costs with the reorganization of two key account executives providing customer service to medium and large customers are also included in this value. When compared to 2017 levels adjusted for inflation, UPPCO's 2019 projected costs have decreased ($84,847) in FERC 908.

Q. Please explain 2019 Forecast Adjustment 8 as evidenced in Exhibit A-18, 2019 Forecast Adjustments.

A. UPPCO has calculated the incremental wage increase for the customer assistance operational area to be $8,120. This calculation is further supported by Exhibit A-23, Salary & Wage Adjustment, line 23. Because UPPCO increased 2017 costs by the 2.66% inflation factor and knowing that the 2019 projected wage adjustment for union workers is 3.5%, UPPCO applied the incremental 0.84% to FERC 903 to account for this adjustment. Consequently, the total FERC 908 net adjustment is ($76,727), the sum of the Forecast Adjustment 7 and Forecast Adjustment 8.

Q. Please explain 2019 Forecast Adjustment 9 as evidenced in Exhibit A-18, 2019 Forecast Adjustments.

A. As related to FERC 907 (Supervision), UPPCO has included costs in this account that focus on supervisory leadership and customer support and engagement. These costs did not exist in 2017 as certain positions and reporting structures did not yet exist, as the Company was still in the process of fully standing itself up as a new Michigan-only utility. UPPCO has now added critical customer supervisory and engagement personnel and associated costs to ensure that customer assistance and communication is prioritized for its customers. 2019 projected test year costs in this category are expected to increase by $233,451 when compared to the 2017 historical test year.

Q. Please explain 2019 Forecast Adjustment 10 as evidenced in Exhibit 2019 Projected Test Year Forecast Adjustments.

A. In the 2017 historical test year, UPPCO spent $382,405 regarding information and instructional advertising as represented in FERC 909 (Customer Engagement). UPPCO, for the 2019 projected test year, is expecting to spend $276,299, a decrease of ($90,650).

Q. Regarding Forecast Adjustment 11, please describe how the Total Pension & OPEB expense in the 2019 projected test year is derived.

A. Willis Towers Watson, on behalf of UPPCO, performs the calculations required by the accounting standards each year, and UPPCO's external auditor, Deloitte, reviews the actuarial assumptions used to ensure consistency with GAAP. UPPCO utilized these numbers to inform the 2019 projected values.

Pension and retiree postretirement benefit plan expenses are determined using an actuarial analysis, which is performed in accordance with ASC 715-30 Pension Plans (formerly SFAS No. 87), and ASC-715-60 Defined Benefit Plans – Other Postretirement Benefits (formerly SFAS No. 106). UPPCO follows Generally Accepted Accounting Principles ("GAAP") for its financial statements. The provisions of GAAP, ASC 715-30 and ASC -715-60 describe the methodologies and assumptions used to calculate and account for pension and postretirement expenses.   ASC 715-30 and ASC 715-60 require an annual determination of the pension and postretirement benefit expense for the year. The pension and post retirement expenses are determined by the actuary each year based upon employee census data, current plan provisions, plan asset performance and other actuarial assumptions.

There are four components of the ASC 715-30 pension, and ASC 715-60 postretirement benefit expenses. They are (1) service cost, (2) interest cost, (3) expected earnings on plan assets, and (4) amortization of gains and losses, prior service costs, and any transitional amounts. Each of these are explained below:

1. Service cost represents one-year's pro-rata share of the expected benefits earned during the year by current employees.
2. Interest cost represents interest on the plan's benefit obligations (liabilities) due to the passage of time.
3. There is also an assumption regarding the expected return on assets for the year, which is measured against the actual returns for the period. This rate of return assumption is intended to be a long-term assumption of the return on plan assets.
4. The final component represents the amortization of various plan experiences that were not anticipated by actuarial assumptions.

To calculate the pension plan's total benefit obligation, the actuary uses a number of assumptions including mortality tables, retirement rates from UPPCO, anticipated salary increases, interest crediting rate and discount rates.

For 2019, the long-term rate of return on plan assets is 5.15%. The discount rate is 3.55%, the rate of compensation/salary increase is 4.00% and the interest credit is 3.05%.

The other postretirement benefits obligation is determined based upon health care inflation trend rates, mortality tables, retirement rates, actual retiree health care claims experience, and a discount rate. For 2019, the long-term rate of return on plan assets is 5.15%, the discount rate is 3.61% and the health care cost trend rate – current 6.00%, and for the long term, 5.00%.

Q. Regarding Forecast Adjustment 11, what are UPPCO's 2019 projected test year Pension and OPEB expenses and how do they compare with the 2017 historical test year?

A. As listed below, the 2019 projected test year values are sourced directly from UPPCO's actuarial consultant Willis Towers Watson. Please finds Exhibits A-25.1, A-25.2, and A-25.3, regarding the Willis Towers & Watson Report on Pension & OPEB, as supporting testimony. The sum of Total Pension & OPEB, as represented on line 8 of Exhibit A-19, FERC 926 Summary, represents a subtotal of the following expenses: pension expense (line 3), postretirement medical (line 4), pension restoration (line 5), supplemental employee retirement plan (line 6) and postretirement benefit costs (line 7).

As evidenced on Exhibit A-19, FERC 926 Summary on line 3, UPPCO's 2019 projected test year total for pension expense is $883,068. UPPCO's 2017 historical test year total for pension expense was $1,171,647.

Also, as evidenced in Exhibit A-19, FERC 926 Summary on line 4, the 2019 projected test year total for UPPCO's post-retirement medical expense is ($242,004) as compared to the 2017 historical test year expenses of ($89,775).

As evidenced in Exhibit A-19, FERC 926 Summary on line 5 and 6, respectively, UPPCO also maintains a pension restoration and Supplemental Employee Retirement Plan ("SERP") pension plan. The 2019 projected test year totals for pension expenses under these two plans, as projected in accordance with ASC 715-30, are $35,491 and $11,751, respectively. UPPCO's 2017 historical test year expenses for pension restoration and SERP are $33,676 and $11,150, respectively.

Also, as evidenced in Exhibit A-19, FERC 926 Summary on line 7, the 2019 projected test year total for UPPCO's post-retirement life benefit expense is $120,955 as compared to the 2017 historical test year expenses of $72,417.

In sum, as evidenced in Exhibit A-19, FERC 926 Summary on line 8, the 2019 projected test year, total Pension & OPEB expense is $809,261 (column d). In the 2017 historical test year, total Pension & OPEB expense was $1,199,114 (column b). When compared to 2017 levels and escalated with two years of inflation (column c), this change represents a cost decrease of $454,495 (column c) primarily due to better than anticipated market returns.

Q. Regarding Forecast Adjustment 12, please describe what cost items are included in Other Benefits Expense in the 2019 projected test year, as well as 2017 historical test year.

A. The sum of Total Other Benefit Expenses, as represented on line 21 of Exhibit A-19, FERC 926 Summary, represents a subtotal of the following expenses: employee costs and benefits (line 11), company cash match 401K (line 12), frozen sick leave (line 13), active dental (line 14), active medical (line 15), employee tuition reimbursement (line 16), company provided life insurance (line 17), defined contribution plan (line 18), long-term disability (line 19) and short-term disability (line 20). Also, on line 21 of Exhibit FERC 926 Summary, in the 2019 projected test year, total Other Benefits Expense is $3,188,051 (column d). In the 2017 historical test year, Other Benefits Expense was $2,699,313 (column b). When compared to 2017 levels escalated with two years of inflation (column c), this change represents a cost increase of $343,225 (column d) primarily driven by increased Medical Benefits expense due to market forces and increased number of employees.

Q. Please provide a summary and comparison of the Pension & Other Postemployment Benefits ("OPEB"), as well as the Other Benefits Expense for the 2019 projected test year and the 2017 historical test year.

A. Please reference Exhibit A-19, FERC 926 Summary. On line 23 of this exhibit, in the 2019 projected test year, total Pension & OPEB expense and Other Benefits Expense is $3,997,312 (column d). In the 2017 historical test year, total Pension & OPEB expense was $3,898,427 (column b). When compared to 2017 levels and escalated with two years of inflation (column c), this change represents a cost decrease of $111,270 (column e).

Q. Please explain 2019 Forecast Adjustment 13 and Forecast Adjustment 14 as evidenced in Exhibit A-18, 2019 Forecast Adjustments.

A. UPPCO has a concurrent depreciation case in MPSC Case No. U-18467 whereby the Company is asking to decrease total depreciation and amortization expense by $1,808,795. Regarding Forecast Adjustment 13, the adjustment for software amortization expense is $1,416,405. Regarding Forecast Adjustment 14, the adjustment for all other plant categories such as distribution, generation and general is $392,390. Company Witness Haehnel provides supporting testimony in this regard.

Q. Please explain 2019 Forecast Adjustment 15 as evidenced in Exhibit A-18, 2019 Forecast Adjustments.

A. Regarding the Tax Cut and Jobs Act of 2017 ("TCJA") tax impact, on June 28, 2018 an Order was issued in Case No. U-20111 directing UPPCO to file application for Calculation C prior to October 1, 2018. The 2019 Forecast Adjustment 15 represents the Calculation C value amortized over a forward-looking 5 years. The 2019 projected test year value is $938,469 resulting in a decrease in tax expense. This 2019 projected test year credit regarding TCJA Calculation C is evidenced on line 10 in Schedule C8 of Exhibit A-13. In column (b) of Schedule C8, the Company divides the $4,692,346 regulatory liability by 5 years to derive the $938,469 decrease in tax expense which is represented on line 10, columns (c) and (d).

Q. At the end of 2017, did UPPCO record a regulatory liability related to net excess deferred income tax liabilities related to its regulated operations? Please explain.

A. Yes, UPPCO recorded approximately $6.3 million at 2017-year end based upon the difference between $13.9 million at prior tax rates (pre-TCJA) and $9.2 million at new tax rates (post-TCJA) grossed-up for taxes. Of this $4.7 million excess liability, an approximately $6.9 million excess deferred tax liability relates to categories of tax deductions that are subject to the income tax normalization requirements of the Internal Revenue Code. These rules govern the handling of this excess within the rate setting process as well as any deferred tax assets related to net operating losses that are allocable to the items. Under the tax normalization requirements, UPPCO is required to use the average rate assumption method for amortizing the amounts through tax expense for ratemaking purposes.

In addition to the $6.9 million excess deferred tax liability UPPCO has recorded an excess deferred tax asset related Goodwill of $6.7 million. UPPCO also proposes to allocate this amount plus $0.2 million of the excess deferred tax asset related to net operating losses such that the net of the categories subject to the income tax normalization requirements, Goodwill and allocated net operating loss is zero. The amortization of this group of items is proposed to be synchronized such that the net annual effect of the amortization of this group is zero. Relative to the remainder of the excess, the entire $4.7 million after considering the allocation of the deferred income tax assets and liabilities described above, UPPCO proposes treating this group in aggregate and establishing a single amortization period to reverse as part of its next rate case filing. Because of its circumstance resulting from the divestiture from its former parent company in 2014, UPPCO does not have material pre-existing regulatory tax assets and liabilities needing to be re-measured due to the tax rate change.

Q. Please explain 2019 Forecast Adjustment 16 as evidenced in Exhibit A-18, 2019 Forecast Adjustments.

A. UPPCO has a concurrent depreciation case in MPSC Case No. U-18467 whereby the Company is asking to decrease depreciation and amortization expense by $1,808,795. Holding everything else constant, UPPCO decreased the accumulated depreciation reserve amount by the depreciation expense amount noted in 2019 Forecast Adjustments

13 & 14 such that the net plant in service values would increase an equivalent amount. Company Witness Haehnel provides supporting testimony in this regard.

2019 PROJECTED TEST YEAR FINANCING PLAN

Q. For the 2019 projected test year, what equity ratio is UPPCO currently targeting?

A. UPPCO is currently targeting a common equity ratio of 58.79% for the 2019 projected test year. During the 2017 historic test year, UPPCO maintained an average 53.19% common equity ratio. UPPCO is not planning to increase its long-term debt position of $108,200,000 and the Company is planning to manage its short-term debt position at approximately $7,500,000.

Q. What benefits does a capital structure with a higher equity ratio provide?

A. Higher equity ratios provides an increased ability to resist negative financial pressures and creates a buffer to protect against unexpected adverse developments. This buffer ensures that distortions can be better managed and remedied without impairing either the orderly conduct of the business, or the credit quality of present or future security issuances. The higher equity ratio also helps ensure that UPPCO has access to capital at reasonable rates when UPPCO may need it, thereby benefiting its customers.

Q. What is UPPCO's recommendation for the cost of equity capital for UPPCO?

A. UPPCO is requesting a 10.5% ROE for the 2019 projected test year as described in, and supported by, the direct testimony of Witness Adrien McKenzie.

Q. In summary, what is your recommendation regarding the required common equity ratio and the required ROE for the 2019 projected test year?

A. Building on the supporting testimony offered by Company Witness McKenzie, UPPCO recommends that the average common equity ratio be set at 58.79% with an ROE of 10.5%. These values are recommended because:

1. They provide a fair return to investors commensurate with competitive investment vehicles available;

2. They reflect the greater business risk associated with operating a smaller, rural utility in a low growth environment: and

3. They recognize that UPPCO has, and will continue to deliver, safe and reliable service to its customers, for which its shareholders should be properly compensated for delivering on its commitment to those customers.

Q. Have there been any recent changes in UPPCO's or UPPCO's parent company's credit rating?

A. Yes. On September 18, 2019, Moody's downgraded UPPCO's parent company's credit rating from Baa3 to Ba1 (below investment grade). Given the timing of this late change, UPPCO has decided not to reflect this change in its current filing. To the extent that UPPCO's proposed financing plan and capital structure are modified through this proceeding by other parties, UPPCO will make any corresponding adjustments to its capitalization structure and related components at that time.

2017 HISTORICAL TEST YEAR REVENUE DEFICIENCY

Q. Please explain Schedule A-1 of Exhibit A-1.

A. Schedule A-1 of Exhibit A-1 calculates UPPCO's historical 2017 test year revenue deficiency based on its rate base, adjusted net operating income, rate of return and revenue conversion factor. This schedule indicates that the 2017 total company revenue deficiency is $4,282,736, and the 2017 Michigan retail revenue deficiency is $3,485,615. As shown on the schedule, the component parts are taken form the various sources indexed to the left of each value.

2017 HISTORICAL TEST YEAR FINANCIAL METRICS

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

A. Schedule A-2, page 1 of Exhibit A-1 depicts financial metrics on a financial basis for 2013 through 2017. For this period, UPPCO's earned rate of return on common equity was 10.08%, 5.87%, 2.59%, 3.98%, and (3.35%) as seen on line 12.

Schedule A-2, page 2 of Exhibit A-1 depicts additional financial metrics on a financial basis for 2013 through 2017, 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 depicts additional financial metrics on a financial basis for 2013 through 2017, 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 depicts additional financial metrics on a ratemaking basis for 2013 through 2017. For this period, UPPCO's earned rate of return on common equity was 9.90%, 8.02%, 3.62%, 6.20%, and 6.00% as seen on line 73.

Schedule A-2, page 5 of Exhibit A-1 depicts additional financial metrics on a ratemaking basis for 2013 through 2017, 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 depicts additional financial metrics on a ratemaking basis for 2013 through 2017, 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.

2017 HISTORICAL TEST YEAR RATE BASE

Q. Please explain Schedule B1 of Exhibit A-2.

A. Schedule B1 of Exhibit A-2 calculates UPPCO's 2017 historical test year rate base. The 2017 total company rate base is $254,699,521, and the 2017 Michigan retail rate base is $251,943,359, 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.

A. Schedule B2 of Exhibit A-2 depicts UPPCO's 2017 projected test year utility plant. The 2017 total company utility plant is $324,349,374, and the 2017 Michigan retail utility plant is $320,210,355, as shown on line 13. All values shown are 13-month averages.

Q. Please explain Schedule B3 of Exhibit A-2.

A. Schedule B3 of Exhibit A-2 depicts UPPCO's 2017 historical test year accumulated provision for depreciation. The 2017 total company accumulated provision for depreciation is $129,894,825, and the 2017 Michigan retail accumulated provision for depreciation is $128,068,468 as shown on line 2. All values shown are 13-month averages.

Q. Please explain Schedule B4 of Exhibit A-2.

A. Schedule B4 of Exhibit A-2 calculates UPPCO's 2017 historical test year working capital. The 2017 total company working capital is $60,244,973, and the 2017 Michigan retail working capital is $59,801,472 as shown on line 38. All values shown are 13-month averages.

2017 HISTORICAL TEST YEAR OPERATING INCOME

Q. Please explain Schedule C1 of Exhibit A-3.

A. Schedule C1 of Exhibit A-3 calculates UPPCO's 2017 historical test year adjusted net operating income. The 2017 total company adjusted net operating income is $12,396,833 and the 2019 Michigan retail adjusted net operating income is $12,442,486 as shown on line 22. The interest synchronization calculation is shown on page 2 of Schedule C1 of Exhibit A-3.

Q. Please explain Schedule C2 of Exhibit A-3.

A. Schedule C2 of Exhibit A-3 calculates UPPCO's 2017 historical test year gross revenue conversion factor. The 2017 gross revenue conversion factor is 1.6367.

Q. Please explain Schedule C3 of Exhibit A-3.

A. Schedule C3 of Exhibit A-3 calculates UPPCO's 2017 historical test year total revenue. The 2017 total company revenues are $105,302,888, and the 2017 Michigan retail total revenue is $104,459,903 as shown on line 6.

Q. Please explain Schedule C4 of Exhibit A-3.

A. Schedule C4 of Exhibit A-3 calculates UPPCO's 2017 historical test year total fuel and purchased power cost of $33,670,891 as shown on line 6. This can be compared to fuel and purchased power costs of $48,284,554 approved in UPPCO's last rate case, Case No. U-17895. The reduction in projected fuel and purchased power costs is mainly due to UPPCO's active management of capacity and energy contracts, including the termination of certain legacy purchased power agreements.

Q. Please explain Schedule C5 of Exhibit A-3.

A. Schedule C5 of Exhibit A-3 calculates UPPCO's 2017 historical test year total O&M expense, exclusive of fuel and purchased power. The 2017 total company O&M expense is $36,181,557 and the 2017 Michigan retail total O&M expense is $35,481,121 as shown on line 11.

Q. Please explain Schedule C6 of Exhibit A-13.

A. Schedule C6 of Exhibit A-3 depicts UPPCO's 2017 historical test year total depreciation and amortization expense. The 2017 total company total depreciation and amortization expense is $11,785,410, and the 2017 Michigan retail total depreciation and amortization expense is $11,620,862 as shown on line 6. Depreciation on line 3 was calculated based upon the depreciation rates approved in Case No. U-15989.

Q. Please explain Schedule C7 of Exhibit A-3.

A. Schedule C7 of Exhibit A-3 depicts UPPCO's 2017 historical test year total for taxes other than income taxes. The 2017 total company total taxes other than income taxes is $6,460,336, and the 2017 Michigan retail total depreciation and amortization expense is $6,377,932 as shown on line 29.

Q. Please explain Schedule C8 of Exhibit A-3.

A. Schedule C8 of Exhibit A-3 depicts UPPCO's 2017 historical test year federal income taxes. The 2017 total company federal income taxes are $4,011,394, and the 2017 Michigan retail income taxes are $4,062,821 as shown on line 14.

Q. Please explain Schedule C9 of Exhibit A-3.

A. Schedule C9 of Exhibit A-3 depicts UPPCO's 2017 historic test year state income taxes. The 2017 total company state income taxes are $796,468 and the 2017 Michigan retail state income taxes are $803,790 as shown on line 15.

Q. Please explain Schedule C10 of Exhibit A-3.

A. Schedule C10 of Exhibit A-3 depicts UPPCO's 2017 historical test year local taxes. The 2017 total company local taxes are $0, as shown in the exhibit.

Q. Please explain Schedule C11 of Exhibit A-3.

A. Schedule C11 of Exhibit A-3 depicts UPPCO's 2017 historic test year AFUDC. The 2019 total company AFUDC is $0 as shown on line 5.

2017 HISTORICAL TEST YEAR CAPITAL STRUCTURE

Q. Please explain Schedules D1 through D5 of Exhibit A-4.

A. In general, Schedules D1 through D5 of Exhibit A-14 support and calculate UPPCO's capital structure, cost of capital, and required rate of return for the 2017 historic test year.

Schedule D1 develops UPPCO's 2017 historic test year overall rate of return of 6.9337%, as shown on line 22, based on UPPCO's 13-month average capital structure, and a 10.0% ROE.

Schedule D2 develops UPPCO's 2017 historic test year cost of long-term debt of 4.8821%, based on a 13-month average, as shown on line 24.

Schedule D3 develops UPPCO's 2017 historic test year cost of short-term debt of 2.526%, based on a 13-month average, as shown on line 14.

Schedule D4 indicates that UPPCO has no preferred equity outstanding, as shown on line 2.

Schedule D5 develops UPPCO's 13-month average balance of Adjusted Common Equity of $122,931,164 for the 2017 projected test year, as shown on line 16.

2017 HISTORICAL TEST YEAR KNOWN & MEASURABLE ADJUSTMENTS

Q. What known and measurable adjustments did UPPCO make to the historical 2017 test year?

A. The only known and measurable adjustment UPPCO made for the historical 2017 test year was explicitly accounting for a large O&M credit received from a contractor valued at $800,000. For accounting purposes, FERC 923 was apportioned $768,459 and FERC

929 was apportioned $31,541. Without adjusting for this atypical invoice credit, the Company's expenses would be understated by $800,000.

2019 COMPENSATION & BENEFITS

Q. What information and context is useful with regard to the evaluation of UPPCO's 2019 compensation and benefits?

A. UPPCO was divested from its former parent company in 2014. Over the course of two concurrent 18-month and 30-month transition services agreements with its former out-of-state parent company, UPPCO stood-up its Michigan-only operations. Over time, UPPCO has continued to add staff where appropriate and these changes are largely represented in the exhibits related to compensation and 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 is reviewed at least annually to ensure our compensation programs will attract and retain a quality workforce to serve our customers.

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.

Q. When was UPPCO's Compensation Plan last updated?

A. June 8, 2017.

Q. Does UPPCO's Compensation Plan include Incentive Pay?

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 2019 projected test year?

A. Pursuant to language from the Commission Order in MPSC Case No. U-17895, UPPCO has included only Pay-At-Risk Pay in the 2019 projected test year as it does not include a "financial qualifier." (page 30) The Incentive Pay is not included in the 2019 projected test year.

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.

Q. Does UPPCO's Pay-at-Risk pay substantively differ from the "incentive compensation" plan outlined in the Commission's order (page 30) approving rates in Case No. U-17895 whereby the Commission rejected the incentive compensation plan because the record evidenced that a "financial qualifier" provided a return to investors? Please explain.

A. Yes. UPPCO's Pay-at-Risk pay, is predicated on meeting safety and operational goals. No financial qualifiers are utilized in determining Pay-at-Risk pay.

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 reducing the cost of service to customers and increases in operating efficiencies.

Q. Does UPPCO's Incentive Pay substantively differ from the "incentive compensation" plan outlined in the Commission's order (page 30) approving rates in Case No. U-17895 whereby the Commission rejected the incentive compensation plan because the record evidenced that a "financial qualifier" provided a return to investors? Please explain.

A. No, Incentive Pay utilizes the EBIDTA metric as a qualifier. UPPCO does disagree though and believes that this qualifier also provides a benefit to customers as it encourages costs reductions and improved operating efficiencies. However, based on the previous ruling, UPPCO has not included this Pay in the 2019 Projected Year.

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 2019 projected test year value of the Pay-At-Risk target?

A. UPPCO's Pay-At-Risk target is $806,400.

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 hired prior to May 1, 2018 and eligible dependents.

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

UPPCO offers Medical, Health Savings Account, Prescription, 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, Business Travel Accident, 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.

Q. Why does UPPCO offer these benefits?

A. UPPCO offers benefits that allow us 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. 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. Please describe Total Medical Benefits, as defined by UPPCO.

A. As represented in Exhibit A-19, FERC 926 Summary, UPPCO defines Medical Benefits as including general medical plan, prescription plan and vision plan benefits

1. Medical plan benefits: The medical with prescription plan is a High Deductible Health Plan (“HDHP”) underwritten by Blue Cross Blue Shield of Michigan (“BCBSM”). Employees must satisfy a specific calendar year deductible for an individual (employee only) or a different calendar year deductible for an employee + spouse/child (two-person contract) or employee + family (3+ person contract) for in network services. For out of network services, deductible amounts increase, respectively. After satisfying the deductible, BCBSM pays 80% of the approved cost of service and the employee is responsible for a 20% coinsurance for in network services. For out of network services, the cost share after deductible is 60% BCBSM / 40% Employee. Once an employee or employee/family has reached a total out of pocket maximum in covered in-network medical spend, the employee/family claims are covered by BCBSM 100%. Out of network expenses are considered separate from in-network expenses.

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. Employees must utilize the BCBSM network to receive in network coverage. By utilizing network providers, services are being rendered at a discounted rate, negotiated between providers and BCBSM. This is meaningful because in 2017 UPPCO was transitioned to an “experience” rated system by BCBSM, receiving a 39% rate increase over 2017. Through educating medical consumerism to employees and realizing benefits through the Company’s Wellness Program, UPPCO is realizing more favorable utilization of the plan, resulting in more stable premium fluctuations whereby premiums are more reasonably covering expenses. UPPCO has also implemented additional programs into the Wellness Program such as a nicotine cessation program and lifestyle coaching for employees and spouses that choose to participate. By quitting smoking and making healthier lifestyle choices, employees will not have as many medical claims, which will positively impact UPPCO’s rating experience.

2. Prescription benefits: Prescriptions are integrated with the HDHP medical plan and are included in the deductible, meaning that the employee is responsible for 100% of the cost of prescriptions until they have met the individual or family deductible. For out-of-network pharmacies, employees are responsible for the in-network co-pays plus an additional 20% of the BCBSM approved amount for the drug. Once an employee has reached their total out-of-pocket maximum for the year under the medical plan, BCBSM covers 100% of the prescription cost.

3. Vision benefits: The vision plan is distinct from the medical plan as it 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. This is beneficial for UPPCO because the company realizes premium savings for those employees that do not need the additional coverage of the Premier plan. The Basic Plan is offered at no cost to the employee; however, the out-of-pocket expenses are more substantial than with the Premier Plan. Both plans encourage employees to use in-network providers to keep costs as low as possible. Each plan provides for a minimum copay or a maximum allowance depending on the service or type of corrective device used.

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. In previous practice, bargaining unit and administrative employees paid different premium amounts. To remain consistent across workgroups, both segments of employees now have the same HDHP cost share effective January 1, 2017.

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. Employees pay 50% of the cost of either plan, with UPPCO paying the remaining 50%.

Q. Please describe the Dental Benefits.

A. The dental plan is distinct from the medical plan and underwritten by Delta Dental of Michigan. The plan is a traditional indemnity design with benefits payable regardless of the provider chosen. However, employees are encouraged to use a provider that participates in the Delta Dental Preferred Provider or Premier network to keep costs as low as possible. UPPCO monitors utilization and provider network usage on an annual basis and educates employees accordingly, so they can be better utilizing providers and minimize utilization rating in the premiums.

Employees must satisfy a specific calendar year deductible, whether they are an individual employee or an employee with covered dependents. Services are categorized into four separate benefits: (i) Preventive and Diagnostic Services; (ii) Basic Dental Care; (iii) Major Care; and (iv) Orthodontia.

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. Employees pay 40% of the cost, with UPPCO paying 60% of the cost.

Q. Please 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 $2,650 for Limited Use or Health Care FSA or $5,000 for Dependent Care if married filing jointly. As employees reduce their taxable income, UPPCO also reduces its payroll taxes, which saves the Company and its customers money.

Q. Please describe the Life Insurance Benefit.

A. UPPCO offers Basic Life, Supplemental Life and Dependent Life insurance. Employees receive life insurance benefits equal to twice their base annual pay with a minimum of $25,000, maximum of $200,000 for bargaining unit employees and $500,000 maximum for administrative employees. This benefit is 100% Company paid. If employees wish to purchase additional life insurance, they have options through the supplemental life insurance program. In addition to the Company provided basic life insurance, employees can elect supplemental life benefits for themselves, their spouse and their child(ren). For employee only coverage, employees can choose from 1, 2, 3, 4 or 5 times their annual base pay. The maximum amount of Supplemental Life Insurance employees can purchase for themselves is $500,000. UPPCO pays 100% of the Basic Life Component and the employee is responsible for all other optional supplemental coverages.

Q. Please describe the Accidental Death and Dismemberment Benefit.

A. Accidental Death and Dismemberment ("AD&D") provides benefits in the event of an accidental injury that result in the death or dismemberment of a covered person. It is payable in addition to any life insurance the employee may have. UPPCO offers Basic AD&D and Supplemental AD&D. Similar to the Life Insurance Benefit, UPPCO pays

100% of the cost of Basic AD&D, while the employee is responsible for any optional supplemental options. There are no underwriting requirements for AD&D coverage.

Q. Please describe the Short-Term Disability Benefit.

A. In the event illness or injury prevents employees from being able to work, UPPCO provides disability benefits to ensure the continuation of their income. Eligible employees are automatically enrolled and covered by both short-term and long-term disability benefits. This benefit is for employees only. It does not pay for a spouse or child disability. This benefit is 100% employer paid.

Q. Please describe the Long-Term Disability Benefit.

A. If an employee is still unable to return to work for an extended period, 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. This benefit is 100% employer paid.

Q. How long is the Long-Term Disability Maximum Benefit duration?

A. The maximum benefit duration is based on the age of the employee on the date the disability begins.

Q. Please describe the Employee Assistance Program Benefit.

A. The Employee Assistance Program ("EAP") provides up to eight (8) counseling sessions for employees and their family members at no cost to the employee or their family members. There are also counselors available on a 24-hour/7 days a week basis. EAP helps employees and their family deal with life's stresses. The EAP program offers professional support and direction to resolving employees' problems or concerns. The EAP also provides both self-help resources online, as well as confidential counseling for issues.

Q. Please 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. Please describe the Matching 401(k) Savings Plan Benefit.

A. The 401(k) Plan provides opportunities for tax effective savings. There are two 401(k) segments, based on when an employee was hired, due to pension plan eligibility and participation.

Key features of the 401(k) plan are:

(1) 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 their 401(k) plan. Employees are always 100% vested in the Company match.

(2) 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 their 401(k) plan. The match occurs automatically, and employees are always 100% vested in the Company match.

Non-Elective Age + Service Contribution - 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. Participants are placed in groups based on their age plus f 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. The percentage of total eligible compensation made as a contribution within the groups are as follows: age 0 - 34 = 3%, 35 - 49 = 4%, 50 - 64 = 5%, 65 - 79 = 6%, and age 80 and above 7%.

Q. Please 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. Please describe the Wellness Program Benefit.

A. UPPCO offers a formal wellness program 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 to catch potential health concerns early, before becoming a major concern. This is important because UPPCO's premiums for the medical program are based on claims experience. The more "well" or healthy the UPPCO population is, the more positive claim results will be, which in turn will help contain premium costs. By offering a Wellness Program, employees and rate payers benefit from lower health care costs by employees making healthier lifestyle choices. For employees enrolled in the Medical HDHP/HSA plan, UPPCO is providing incentives in the form of added employer HSA contributions. For employees not enrolled in UPPCO's medical program, wellness credits are distributed via payroll.

Q. Describe the Tuition Reimbursement Benefit.

A. UPPCO recognizes the value of continuing education. The Tuition Reimbursement Benefit 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. This benefit is available to any active, regular full-time employee. To engage in this program, employees must apply for consideration through their leader and the human resources department, to ensure that the requested education program meets the program guidelines 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. Please describe the Adoption Assistance Benefit.

A. This benefit applies to all 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 Company shall pay an employee up to $3,000 for a legal adoption upon finalization of the adoption (employee has physical custody of child). To be eligible for payment, an employee must be an active regular full-time employee at the time the adoption is finalized. An employee must have more than one year of service with the Company in a regular full-time status at the time the adoption is finalized. The maximum payment per adoption is $3,000, with an annual limit of $3,000 per employee. Proof of itemized costs must be submitted. Payment under the Adoption Assistance program is considered taxable income to the 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. This is beneficial to the Company because it discourages employees from enrolling in multiple benefit programs unnecessarily, which increases the claims experience and premiums.

Q. Please describe the paid time away programs.

A. UPPCO recognizes the need for work-life balance. In supporting employees to manage their work and personal lives, UPPCO offers paid holidays, vacation time, sick time, Family Medical Leave (FMLA), and personal time. By offering these benefits, UPPCO's time away package is competitive, helping to retain quality employees.

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 their years of service.

Administrative employees are granted ten (10) sick days and one (1) personal day per year and Bargaining unit employees accrue one (1) sick day per month and are granted two (2) personal days per year.

Q. What benefits does UPPCO offer to retirees?

A. Medical (closed to new entrants), Prescription (closed to new entrants), Dental (closed to new entrants and only applicable to some retirees), Vision (closed to new entrants and only applicable to some retirees), Life Insurance (closed to new entrants), and Pension Payments (closed to new entrants).

Q. Please 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 the same HDHP medical coverage as Active Employees. Retirees over the age of 65 are offered Medicare Advantage with Prescription Drug Coverage ("MAPD") through BCBSM. There is one small segment of retirees, with an average age of 85, enrolled in a Medigap plan through United American paired with Express Scripts prescription coverage. Due to the age of this final segment and high potential for confusion with change, UPPCO decided not to change their coverage to the BCBSM MAPD plan.

For the pre-65 retiree plan, retirees must satisfy a certain calendar year deductible for an individual (retiree only) or a different value for a retiree + spouse/child (two-person contract) or retiree + family (3+ person contract) for in-network services. For out-of-network services, deductible amounts increase respectively. After satisfying the deductible, BCBSM pays 80% of the approved cost of service and the employee is responsible for a 20% co-insurance payment for in network services. For out-of-network services, the cost share after deductible is 60% BCBSM / 40% employee, respectfully. Once a retiree has reached a total out-of-pocket maximum in covered in-network medical spend, the employee or employee/family claims are covered 100% by BCBSM . Out-of-network expenses are considered separate from in-network expenses.

The BCBSM MAPD plan requires each covered individual to satisfy a certain deductible. After satisfying the deductible and any applicable co-pays, the plan will cover 90% of the cost of a service and the member/retiree is responsible for the remaining 10% for in-network services. For out-of-network services, the plan will cover 80% after the out-of-network deductible is met, and the member/retiree is responsible for the remaining 20%. For the plan to cover services at 100%, employees must satisfy the out-of-pocket maximum.

The United American Gap Plan with Express Scripts Prescription coverage has full medical coverage, after coordinating with original Medicare. Members are responsible for prescription co-pays that align with Express Scripts coverage.

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 in the early 1980s.. 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 can accrue Retiree Medical Care Credits. These employees were active employees who had retiree medical coverage available to them at the time UPPCO closed retiree medical to future administrative employees. To honor their agreements, these employees can accrue credits to pay for their coverage. Once the credits have been exhausted, UPPCO no longer pays for any portion.

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, Non-Bargaining Unit Employees, with the exception that the retirees have a different orthodontia limit.

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, Non-Bargaining Unit Employees and retired or currently active Bargaining Unit Employees. It is a closed benefit to future employees of UPPCO.

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

A. A couple of things that are relevant to this case are that:

(1) 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 but still implementing cost-savings measures.

(2) Wherever possible, benefit providers were changed to Michigan based companies. For example, the medical and wellness plans are now provided by BCBSM and dental is provided by Delta Dental of Michigan. UPPCO has also partnered with a benefits broker, VAST, which is an Upper Michigan based insurance agency, familiar with Michigan insurance rules and the unique territory of Michigan insurance competition.

2019 JUST AND REASONABLE

Q. When compared to historical values, how have the Company's Operating Expenses performed when compared to historic levels since the sale of UPPCO from its former parent company?

A. Despite declining volumes, UPPCO has still managed to lower operating expenses on average since it was divested from its former parent company. As evidenced in Exhibit A-17, Financial Summary, on line 2 UPPCO's 2019 projected Operating Expenses are lower by $8,559,006 when compared to 2014 levels. This decrease represents a compound annual growth rate ("CAGR") of (1.5%) per year. During this timeframe, UPPCO has also seen a decline in sales resulting in lower Operating Revenues of $17,633,463 (line 1). This decrease represents a CAGR of (2.6%) per year.

Q. As outlined in your testimony and exhibits, do you believe the 2019 projected test year costs as represented herein are just and reasonable?

A. Yes.

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.	)	Case No. U-20276
____	)	

DIRECT TESTIMONY AND EXHIBITS OF

GRADON R. HAENEL

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

September 21, 2018

QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Gradon 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 employed by Upper Peninsula Power Company ("UPPCO" or the "Company") as the Director of Regulatory Affairs.

Q. Briefly describe your education background and employment history.

A. I earned my Bachelor of Science degree in Finance from Indiana University of Pennsylvania in 1995. I earned a Master of Science in Resource and Applied Economics from the University of Alaska-Fairbanks in 2004. Within the regulated electric utility industry, I began my professional career at Bangor Hydro Electric Company, as a Rates and Regulatory Analyst in 2005. By 2008, I was the Manager of Rates and primarily responsible for the development of distribution, transmission, and stranded cost revenue requirements, sales and revenue forecasting, as well as the various associated rate and tariff filings at the Maine Public Utilities Commission ("MPUC") and the Federal Energy Regulatory Commission ("FERC"). By 2012, Bangor Hydro Electric Company had acquired Maine Public Service Company becoming a newly formed regulated transmission and distribution utility in Maine, called Emera Maine. At the newly formed Emera Maine, I assumed the role of Manager of Engineering and Asset Management ("Asset Manager") where I was primarily responsible for the operational functions of asset management, capital planning, transmission and distribution engineering, and transmission development. From 2014 through 2016, I worked in the role of Senior Asset Manager at Emera Maine which additionally included oversight of the operational functions of resource planning, scheduling, and dispatch. In 2016, I joined UPPCO as Manager of Financial Planning and Analysis where I was primarily responsible for the development and implementation of financial forecasting, budgeting, and reporting processes during the latter stages of UPPCO's SAP system implementation. In early 2017, I assumed the role of Director of Regulatory Affairs for UPPCO.

Q. Have you previously testified in any regulatory proceedings?

A. Yes. I have testified in several cases before the MPUC in my various roles as Rates and Regulatory Analyst, Manager of Rates, Asset Manager and Senior Asset Manager. Most recently I sponsored testimony and exhibits in Michigan Public Service Commission ("MPSC" or "Commission") Case Nos. U-18265, U-18254, U-18335, U-18467, U-20111, and U-20184 on behalf of UPPCO.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is provide direct support for the following areas of UPPCO's general rate application for the 2019 projected test year.

1. Depreciation & Amortization. I will support Forecast Adjustments 13, 14 and 16, as identified in Exhibit A-18 of Company Witness Kates. In alignment with UPPCO's concurrent MPSC case in U-18467, UPPCO has adjusted the 2019 projected test year values for depreciation and amortization expense, as well as, the associated depreciation reserve amount.

2. Revenue Offset (Credit) Update. I will support line 18 as of Schedule A-1 of Exhibit A-11 of Company Witness Kates. UPPCO proposes to amend the annual credit for the remainder of the 6-year period.
3. Escanaba Hydro Facilities inclusion in Rate Base. I will support the inclusion of the primary revenue requirement components of transferring these facilities into rate base while keeping all other customers held harmless from a rate perspective.
4. 2019 Cost of Service Study Update. I will support the Company's class cost of service study.

Q. What exhibits are you sponsoring?

A. I am sponsoring the following exhibits, which were all prepared by me or under my direct supervision:

1. Schedule F1 of Exhibit A-16, 2019 Cost of Service Study ("COSS")
2. Exhibit A-40, Revenue Offset (Credit) Update
3. Exhibit A-41, Escanaba Hydro Facility Forecast Adjustments

DEPRECIATION & AMORTIZATION

Q. Please explain 2019 Forecast Adjustment 13 and Forecast Adjustment 14 as evidenced in Exhibit A-18 of Company Witness Kates regarding depreciation and amortization expense.

A. Pursuant to an Order dated July 31, 2017, in Case No. U-18238 regarding rate case filling requirements, the Commission directs the following:

> The depreciation and amortization expense included in these schedules must reflect the depreciation rates approved at the time the utility makes

> its filing, and those rates must be applied to the plan included in its filing. If a utility files a concurrent depreciation case or has a pending depreciation case at the time of the rate case filing, then the utility shall provide a statement within its rate case filing describing the revenue requirement impact of its full depreciation case request.

UPPCO has a concurrent depreciation case, Case No. U-18467, whereby UPPCO is proposing to decrease its annual depreciation and amortization expense by $1,808,795. Of this decrease, $1,416,405 is related to software amortization (Forecast Adjustment 13) while the remaining $392,290 represents the proposed decrease for the distribution, generation and corporate related depreciation expenses (Forecast Adjustment 14).

Q. Please explain 2019 Forecast Adjustment 16 as evidenced in Exhibit 2019 Projected Test Year Forecast Adjustments regarding accumulated depreciation reserve.

A. As mentioned, UPPCO has a concurrent depreciation case, Case No. U-18467, whereby UPPCO is proposing to decrease its annual depreciation and amortization expense as described above by $1,808,795. As represented in Exhibit A-18 of Company Witness Kates, Forecast Adjustment 16 addresses the equivalent positive balance sheet adjustment to its accumulated depreciation reserves within FERC plant account 108 (amortization of utility plant) for $1,416,405 for its decreased software amortization and FERC plant account 111 (depreciation of utility plant) for $392,290 for its decreased distribution, generation and corporate related depreciation.

REVENUE OFFSET (CREDIT) UPDATE

Q. In MPSC Case No. U-17564, the Company agreed to a $26 million revenue credit relating to accounting adjustments made coincident with the previous sale of the Company in 2014. Is the Company providing an update to the credit?

A. Yes.

Q. When did the $26 million revenue credit go into effect?

A. The $26 million revenue credit was included in the revenue deficiency calculation for the 2016 projected test year approved by the Commission in the Company's last rate case, U-17895.

Q. How is the $26 million revenue credit represented within the calculation of UPPCO's jurisdictional revenue requirement model?

A. In Case No. U-17895, the $26,000,000 revenue credit was annualized over a 6-year period which resulted in an annualized revenue reduction of $4,333,333, which was utilized to set rates in the previous rate case.

Q. How was the remaining value of the revenue credit calculated?

A. The $26 million revenue credit within the jurisdictional model is represented as a revenue deficiency. To calculate the credit remaining, UPPCO has calculated the actual revenue deficiency in 2016 and 2017 and added the variance from the planned $4,333,333 per year compared to the actual deficiencies for those first two years. The remaining balance of the credit was then annualized over years 2018 through 2021 as seen in Exhibit A-40 (GRH-2), Revenue Offset (Credit) Update. To do this, the Company first calculated the net income deficiency for both 2016 and 2017 compared to the authorized net income per the last rate case. The Company then grossed-up the net income deficiency values for both 2016 and 2017 by the authorized revenue conversion factors to derive a cumulative revenue deficiency. This cumulative revenue deficiency value was then subtracted from the original $26,000,000 to determine the remaining amount to be credited equally over a subsequent four-year period.

Q. Can you please walk us through these calculations, starting off with detailing UPPCO's authorized net income, excluding the adjustments for the $26 million revenue credit, in 2016 and 2017?

A. In 2016, the authorized net income excluding revenue credits was $12,111,557 and in 2017 the authorized net income excluding revenue credits was $12,425,433, as seen in Exhibit A-40 (GRH-2), Revenue Offset (Credit) Update, line 10 and columns (b) and (c), respectively.

Q. What was UPPCO's adjusted net income in 2016 and 2017?

A. In 2016 the adjusted net income was $10,159,479, and in 2017 the adjusted net income was $10,104,402 as seen in Exhibit A-40 (GRH-2), Revenue Offset (Credit) Update, line 9 and columns (b) and (c), respectively.

Q. What was UPPCO's additional net income deficiency, excluding the impact from the $26 million revenue credit in 2016 and 2017?

A. In 2016 the value of the credit was $1,952,277, and in 2017 the figure was $2,321,031 as seen in Exhibit A-40 (GRH-2), Revenue Offset (Credit) Update, line 11 and columns (b) and (c), respectively.

Q. When applying the revenue conversion factor approved in Case No. U-17895 to the income deficiency values in 2016 and 2017, what are annual revenue credit amounts?

A. After applying the revenue conversion factors, the annual credit amounts in 2016 are $7,528,625, and in 2017 are $8,132,165 as seen in Exhibit A-40 (GRH-2), Revenue Offset (Credit) Update, line 14 and columns (b) and (c), respectively.

Q. Cumulatively, for both 2016 and 2017, what was the total revenue credit, and how much is remaining when compared to the original $26,000,000 million revenue credit value?

A. The cumulative value of the credit is $15,660,790 as seen in Exhibit A-40 (GRH-2), Revenue Offset (Credit) Update line 15 and column (c), and the remaining amount of revenue credit when compared to the original $26,000,000 is $10,339,210 as seen on line 16 and column (a).

Q. How is the Company proposing to credit the remaining $10,339,210?

A. The Company is proposing to remain consistent with the original 6-year credit period, and spread the remaining $10,339,210 credit over the next four-year period beginning in 2018, resulting in an updated annual credit of $2,584,802, as seen in Exhibit A-40, Revenue Offset (Credit) Update, line 21 and columns (d) through (g). Given the mid-year status of 2018, UPPCO believes this approach is conservative as the Company will provide a reconciliation in a future filing to be determined.

Q. As a result of these changes, will the retail customers still be realizing a full revenue credit of the full $26,000,000 over the original term?

A. Yes.

Q. In deriving the revenue deficiency, has the Company appropriately assumed the post-Tax Cut and Jobs Act ("TCJA") of 2017 revenue conversion factor change?

A. Yes. In 2016 and 2017, UPPCO utilized a 1.6367 revenue conversion factor. In 2018 through 2021, UPPCO utilized a 1.3466 revenue conversion factor, which incorporates the post TJCA changes, as seen in Exhibit A-40, Revenue Offset (Credit) Update, lines 18 and 19, columns (b) through (g).

Q. Why is it important to adjust the credit to a lower amortized amount vs. realizing the $26 million in a shorter time period?

A. First, since 2014, UPPCO's earned return has consistently fallen below its authorized return on equity ("ROE"). A significant driver for this situation is related to the $26 million "revenue credit" in the order approving the divestiture from its former parent company in 2014 in Case No. U-17564. This revenue offset (credit) is a contributor to UPPCO's chronic under-earning. The Company anticipates that, absent modifications to the revenue offset mechanism as proposed here within, it will under-earn its allowed rate of return going forward thereby having further credit implications, as further discussed in Company Witness McKenzie.

Second, UPPCO will likely surpass the $26 million credit sometime during the 2018-2019 timeframe. After its six-year term, this revenue credit will cease to exist and, as such, holding everything else constant, would result in a $4,333,333 increase in revenue requirement for customers at that time.

ESCANABA HYDRO FACILITIES

Q. Please describe UPPCO's Escanaba Hydro facilities.

A. The Escanaba Hydro facilities, which are in Escanaba, Michigan, consist of three (3) separate and distinct hydroelectric facilities with a combined generator nameplate capacity of 9,190 kW. These renewable energy facilities physically reside within UPPCO's service territory boundary and have been historically operated and maintained by UPPCO personnel. A description of these facilities is listed below.

1. Dam No. 4 (Boney Falls)
    a. Generator #1: 1,360 kW
    b. Generator #2: 1,700 kW
    c. Generator #3: 1,680 kW
2. Dam No. 3
    a. Generator #1: 1,250 kW
    b. Generator #2: 1,250 kW
3. Dam No. 1
    a. Generator #1: 700 kW
    b. Generator #2: 700 kW
    c. Generator #3: 550 kW

Q. Please describe the regulated nature of UPPCO's Escanaba Hydro facilities.

A. These facilities are wholly-owned by UPPCO and are regulated by the MPSC. The energy produced from these three hydroelectric generating facilities is currently sold to one customer under an MPSC approved special contract and/or Purchased Power Agreement ("PPA), which has a term of ten years under certain contractual conditions. The MPSC approved the most recent special contract on March 27, 2013 in Case No. U-17227. Under the special contract, UPPCO retains ownership and use of the Renewable Energy Credits ("RECs") and appropriately accounts for them in the Company's biennial renewable energy plan, as represented and approved in Case No. U-18235.

Q. How has UPPCO historically categorized these facilities?

A. These facilities were historically deemed and often reported by UPPCO's prior owners as "non-utility" facilities given that that they only serviced one customer. UPPCO asserts that this nomenclature was and is currently inaccurate, as these hydro generating facilities are physically owned by the utility and provide value to UPPCO customers today.

Q. How would UPPCO more accurately qualify these facilities?

A. Since these are owned by the utility, UPPCO believes the appropriate accounting treatment is to include all accounting entries related to these three hydroelectric generating facilities within those of the other normal utility operations. This would include all revenue, capital costs, depreciation, and operating costs. In addition, these have always been regulated facilities as the MPSC has approved all customer contracts related to these facilities.

Q. How is UPPCO representing the Escanaba Hydro facilities in its projected 2019 test year revenue requirement calculations?

A. As evidence, please find Exhibit A-41 2019 Escanaba Hydro Forecast Adjustments. UPPCO has transferred all the related cost components of the Escanaba Hydro facilities into the jurisdictional model as follows:

1. 2019 projected special contract revenue at current terms is represented on line 2 of Exhibit A-41, 2019 Escanaba Hydro Forecast Adjustments. This value of $1,114,883 is based on a 5-year historical average of revenue from 2013 through 2017.

2. 2019 projected operating expenses are represented on line 7 of Exhibit A-41, 2019 Escanaba Hydro Forecast Adjustments. This value of $1,024,952 is also based on a 5-year historical average of expenses from 2013 through 2017.
3. 2019 projected depreciation expenses are represented on line 8 of Exhibit A-41, 2019 Escanaba Hydro Forecast Adjustments. This value of $213,534 is the current depreciation value from the current accounting records.
4. 2019 projected property taxes are represented on line 9 of Exhibit A-41, 2019 Escanaba Hydro Forecast Adjustments. This estimated value of $30,000 is based on current accounting records.
5. 2019 projected plant in service are represented on line 13 of Exhibit A-41, 2019 Escanaba Hydro Forecast Adjustments. This value of $9,294,220 is the current book value of these facilities from the accounting records.
6. 2019 projected accumulated depreciation reserve are represented on line 14 of Exhibit A-41, 2019 Escanaba Hydro Forecast Adjustments. This value of ($2,231,905) is based on the current accumulated depreciation reserve value from the accounting records.
7. 2019 updated contract revenue is represented on line 3 of Exhibit A-41, 2019 Escanaba Hydro Forecast Adjustments. This value of $1,247,836 is based on the incremental change in revenue requirement (i.e., revenue deficiency) that resulted from including the Escanaba Hydro facilities associated with the existing special contract / PPA revenues as well as all related costs included the 2019 projected test year revenue requirement model.

Q. Why is UPPCO proposing to transfer the Escanaba Hydro facilities into rate base?

A. UPPCO considers this a residual, accounting "clean-up" item following the 2014 divestiture from its former parent company, which held an alternative view as to the accounting treatment these utility facilities should have. Since UPPCO is considering a number of options for maximizing future value of these hydroelectric generating facilities, some of which are for the benefit of all UPPCO customers in the future, this shift lays the groundwork for possible alternative treatment in future rate cases.

Q. From a revenue requirement perspective, how will the transfer of the Escanaba Hydro facilities into rate base impact all other UPPCO customers?

A. UPPCO's intention is to insulate its customers from the impact of this transfer and ensure there is impact to the revenue requirement and/or revenue deficiency in this case. To this end, UPPCO has included calculations that assume that the full revenue requirement for these facilities are recovered from the single customer receiving service from these three hydroelectric generating facilities.

Q. Please explain how customers are held harmless?

A. As demonstrated in Exhibit A-41, 2019 Escanaba Hydro Forecast Adjustments, the projected PPA revenues of $1,114,883 at current rates, represented as Forecast Adjustment 1, and the revenue requirement associated with transferring the Escanaba Hydro facilities to rate base are entirely offset by an assumed renegotiated PPA that results in an incremental revenue amount of $1,247,836, represented as Forecast Adjustment 2. This approach will offset any consequential revenue requirement impact for other customers.

COST OF SERVICE STUDY (COSS)

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to discuss and sponsor the class Cost of Service Study ("COSS") for the 2019 projected test year.

Company Witness Stocking's direct testimony in rate design relies on the results of the COSS for the 2019 projected test year to develop UPPCO's proposed changes to rate design.

COSS EXHIBITS, SCHEDULES AND SUB-SCHEDULES

Q. What exhibit and schedules support UPPCO's 2019 COSS study?

A. As demonstrated in Schedule F1 of Exhibit A-16, UPPCO provides its 2019 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 embody the COSS prepared for the retail electric jurisdiction, along with the associated allocation methodologies, supplemental analyses, and data.

OTHER COSS CONSIDERATIONS

Q. What other considerations were considered when developing the 2019 projected test year COSS model?

A. UPPCO incorporated Commission directives from Case Nos. U-18383 and U-20131.

CASE NO. U-20131 (STATE RELIABILITY MECHANISM TARIFF)

Q. Please explain UPPCO's considerations regarding MPSC Case No. U-20131 that were considered when developing the 2019 projected test year COSS model.

A. Pursuant to Section 62 of 2016 PA 341 and as further outlined in the order approving settlement in Case No. U-20131 regarding UPPCO's application for approval of an annual review of its state reliability mechanism charge, it became evident that UPPCO needed to update its COSS model to properly demonstrate certain power supply cost components.

Q. Identify the requirements of the Settlement Agreement in Case No. U-20131, and also explain how UPPCO has addressed each of these requirements in this case.

A. The following requirements, listed below, were outlined in the Settlement Agreement in Case No. U-20131:

(i) Settlement Agreement Point 1:

> 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*;*

UPPCO response: In sub-Schedule O&M of Schedule F1 of Exhibit A-16, on lines 6 and 7, purchased power is listed. Also, fuel is listed on lines 11 and 12. UPPCO's monthly purchase power letters further bifurcate purchased power into "contract" and what is "obtained from the market." These bifurcated values are projected as part of the annual Power Supply Cost Recovery ("PSCR") filing, as well as, reconciled through the PSCR reconciliation process. UPPCO utilizes the same allocation basis in the 2019 COSS.

(ii) Settlement Agreement Point 2:

> *Split the above categories of costs further between demand and energy and provide any supporting information necessary to show how the split was performed and why it is reasonable;*

UPPCO response: In sub-Schedule O&M of Schedule F1 of Exhibit A-16, on lines 6 and 7, purchased power is bifurcated between energy and demand, respectively. Also, fuel is listed on lines 11 and 12.

(iii) Settlement Agreement Point 3:

> *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;*

UPPCO response: First, UPPCO's "purchases pursuant to contract" are established through terms of the contract and not the "hourly LMP." For the other components, these components are projected as part of the annual PSCR filing, as well as, reconciled through the PSCR reconciliation process.

(iv) Settlement Agreement Point 4:

Continue separately identifying fuel and non-fuel power supply expenses and plant and provide any supporting information necessary to show how the split was conducted and why it is reasonable;

UPPCO response: In sub-Schedule O&M of Schedule F1 of Exhibit A-16 on line 15, total fuel and purchased power is identified. This total is comprised of the two items: (1) total purchased power listed on line 8, and (2) total fuel and handling, listed on line 13.

(v) Settlement Agreement Point 5:

Identify where the costs and revenue associated with RTMP are located in the COSS and explain how the disposition of these costs and revenues affects the calculation of the SRM Capacity Charge and why it is appropriate they be treated as proposed;

UPPCO response: In sub-Schedule SUM of Schedule F1 of Exhibit A-16, RTMP revenues are listed on line 6, column (x). Total operating expenses are further listed on line 16, column (x). Regarding the SRM Capacity Charge calculation, RTMP is excluded from this calculation pursuant to the terms of the RTMP tariff. Similarly, this rate class is excluded from the PSCR cost development, as well.

(vi) Settlement Agreement Point 6:

Identify revenues from ancillary services, and any other of the offsets identified by the Commission not previously addressed; and

UPPCO response: In sub-Schedule REV of Schedule F1 of Exhibit A-16, revenues from ancillary services are listed on line 18.

(vii) Settlement Agreement Point 7:

Make a proposal on the appropriate calculation of the SRM capacity charge pursuant to the Commission's prior direction.

UPPCO response: From a timing perspective, UPPCO supports the calculation of the SRM capacity charge in conjunction with UPPCO's annual PSCR plan filing because it is at that point in time that the Company is adjusting its PSCR factor pursuant to its filed and anticipated purchased power costs for the upcoming year. Absent this timing, SRM capacity charges will be out of sync with the capacity charges reflected through the PSCR process. Pursuant to an order in this case, UPPCO proposes to update its SRM capacity charges in concert with its annual PSCR filing.

CASE NO. U-18383 (DISTRIBUTED GENERATION TARIFF)

Q. Please explain Case No. U-20131 and how it affects the 2019 projected test year COSS model.

A. Section 6a(14) of Act 341 directed the Commission to "conduct a study on an appropriate tariff reflecting equitable cost of service" for customers who participate in a net metering program or distributed generation program. The "Inflow/Outflow" tariff must be an adaptable billing mechanism that allows for equitable cost of service.

Q. What was ordered in Case No. U-18383?

A. In any rate case filed after June 1, 2018, a rate-regulated utility must file the Inflow/Outflow tariff, attached to this order as Exhibit A. The rate-regulated utility may also file its own distributed generation tariff, if desired.

Q. From a cost of service perspective, how has UPPCO complied with the directives in the Commission order in Case No. U-18383?

A. UPPCO has updated and performed a class cost of service study that has determined the revenue requirement for each class of customers whereby the costs that customers pay are aligned with the costs that customers cause on the system. In alignment with Exhibit A to the Order in Case No. U-18383, the Company has also developed a new Distributed Generation Rider that can be attached to any metered tariff, excluding other riders, unless otherwise noted on the applicable metered tariff. The updated Net Metering Program tariff and the new tariff Distributed Generation ("DG") Program tariff in Schedule F5 of Exhibit A-16 as supported by Company Witness Stocking.

OVERVIEW OF CLASS COST OF SERVICE STUDY

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

A. A class cost of service study is performed to determine the revenue requirement for each class of customers. This 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 cost study 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 identify some guiding principles of a fundamentally sound approach to preforming a COSS?

A. In general, a sound COSS approach should provide an outcome whereby the costs that certain customers pay should be the costs that those certain customers caused the utility to incur. Cost causation is a central principle which is pertinent to all cost of service studies for allocating costs across customer classes. In theory, cost incurrence (i.e., how costs are apportioned to customer classes) should follow historical embedded cost causation (i.e., which customer classes caused these costs to be originally borne by the utility).

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

A. There are three steps involved in conducting 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 or assign 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 employed to calculate class allocation factors.

FUNCTIONALIZATION

Q. Please describe the process of cost functionalization the Company has employed in the COSS.

A. After all the individual cost components representing the total revenue requirement have been identified the components are separated according to the function or physical service they provide. Typically, 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 centers;
3. Distribution – costs associated with distributing the energy from the transmission system to the end users;
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.

CLASSIFICATION

Q. Please describe the process of cost classification the Company has employed in the COSS.

A. Cost classification is the process of further categorizing the functionalized costs according to the cost driving characteristic of the utility service being provided. The three principal 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, vary with the overall quantity of energy. Customer-related costs are those costs incurred as a result of the number of customers on the system. These costs, such as meters and billing, are incurred to serve individual customers.

ALLOCATION

Q. Once UPPCO's costs of service are functionalized and classified, 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.

COSS MODEL ORGANIZATION & DEFINITION

Q. Please describe the layout and operation of the 2019 COSS model you are sponsoring.

A. The class cost of service model I am sponsoring as Schedule F1 of Exhibit A-16, 2019 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 computation of labor and other allocators.

Q. Please describe the output and sub-schedules of Schedule F1 of Exhibit A-16.

A. The sub-Schedules are identified on the left-most column of the COSS output. 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 some 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 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 cost of service study 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 7.57%. The results summarized on this page set forth the revenue requirements by class needed for each class to pay its respective costs of service.

Pages 9 through 28 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 20 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.

As represented in sub-Schedule REV, allocated class Operating Revenues are provided on pages 28 through 32. The allocation of operation and maintenance expense by account is set forth on pages 29 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 56 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. Note that Income Taxes are not directly allocated to customer classes, but that 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 73 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. Finally, 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. Also, pages 149 through 164 support the unbundled composite of UPPCO's rate structure pursuant to the COS performed.

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

A. Yes. The class cost of service study submitted as Schedule F1 of Exhibit A-16 to 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.

ELECTRIC 2019 CLASS COST OF SERVICE STUDY COST ALLOCATIONS

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 2019 projected 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 2018 projected test year COSS.

A. The customer classes that were utilized in the 2018 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;
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.

Q. Are the customer classes defined in the same manner in UPPCO's 2019 projected test year COSS as they were in UPPCO's Commission-approved 2016 COSS in Case No. U-17895?

A. Yes, they are. However, through rate design, UPPCO is proposing the following: (1) the consolidation of the Iron River and Integrated residential rate classes; and (2) the consolidation of certain Street Lighting classes as discussed by Company Witness Stocking through the Company's rate design discussion.

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

A. The COSS submitted for the 2019 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". Direct assignment of values to the appropriate rate classes was conducted wherever appropriate.

Q. Regarding the classification of FERC account 364 through 368, does the 2019 projected test year COSS classify these accounts in the same manner compared to the COSS approved in UPPCO's last rate case?

A. No, it does not. Previously, UPPCO performed a minimum distribution system ("MDS") study as represented in the Company's filing in Case No. U-17895. These MDS study results were used in the development of the 2016 COSS. Through the development of an MDS, the utility identifies the portion of a distribution account's investment (FERC accounts 364 through 368) which represents an estimated minimum investment required to serve a nominal load at a customer's location. Consequently, the MDS recognizes that this nominal load is the variable customer related cost portion of the investment.

The National Association of Regulatory Utility Commissioners' ("NARUC") manual, entitled the "Electric Utility Cost Allocation Manual," (1992) acknowledges two MDS methods: minimum size system and zero-intercept. Although the purpose of each MDS method is the same, the methodology and underlying data used to perform each study is quite different. The minimum size system method uses a mathematical approach and relies heavily on current installation costs to derive a minimum cost per unit for each type or size of equipment. The zero-intercept method uses a statistical approach and relies heavily on historical plant account data to derive a minimum cost per unit. As often is the case, the method selected is a function of the data available at the time of the study.

That being said, the NARUC Electric Utility Cost Allocation Manual, January 1992, Page 95, acknowledges two major criticisms with using the minimum size system method. The first criticism is that the selection of the minimum size is largely judgmental. The customer related costs can vary significantly with the choice of method used to identify the minimum sized equipment. A method based on historical practice, current practice, or minimum available from a supplier (as long as it meets safety requirements) can all produce different minimum costs and resulting customer cost percentages of the total account(s).

The second criticism is that the minimum size method fails to recognize that even a minimum size distribution system has the capability to carry load that can be considered demand related. Depending on the selected minimum size and customer class, the equipment capability can fully serve a customer's load portion as well. If adjustments are not made to the allocation factors to reflect this load capability, the use of this method will lead to a disproportionate share of demand related costs being allocated to certain customers (i.e. "double dipping"). This is especially true of lower use customers that generally represent the majority of a utility's total customers.

Q. Please summarize the Company's position regarding MDS study method utilized in the 2019 COSS.

A. As evidenced above, the flaws inherent in using the minimum size system result in a larger portion of each account being classified as customer-related; therefore, driving the customer-related costs higher. It is for this reason that UPPCO has chosen not to classify accounts 364 through 368 using the results of the minimum size system MDS study but has chosen to allocate these accounts on a demand allocation factor.

Q. Please explain the considerations relied upon in determining the cost allocation methodologies that are used to perform a COSS.

A. In order to allocate costs within any COSS, the factors that cause the costs to be incurred must be identified and understood. Additionally, the cost analyst needs to develop data in a form that is compatible with, and supportive of, rate design proposals. The availability of data for use in developing alternative cost allocation factors is also a consideration. In evaluating any cost allocation methodology, appropriate consideration should be given to whether it provides a sound rationale or theoretical basis, whether the results reflect cost causation and are representative of the costs of serving different types of customers, as well as the stability of the results over time.

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 customers based on cost causation. In some cases 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 employed in Case U-17895.

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 peaker 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.

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 has identified two significant cost causation relationships. 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 months of coincident peak ("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). Real Time Market Pricing ("RTMP") customers are allocated zero percent of Transmission O&M expense, because within the COSS the RTMP rate schedule is only allocated non- PSCR costs, and the Transmission O&M costs portrayed in the COSS are all PSCR related.

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. However, with respect to customer costs in FERC Account 904 (uncollectible accounts/bad debt expense), the RTMP customer class costs regarding FERC Account 904 are directly assigned to the RTMP class on a 3-year historic net write-off basis. To hold all other rate classes harmless from the RTMP class bad debt expense, the Company has directly assigned all non-RTMP bad debt to the other classes with sales/revenue functions which are evidenced in sub-Schedule ADA of Schedule F1 of Exhibit A-16 on page 140.

CONCLUSION

Q. Please summarize the results of the 2019 COSS for the 2019 projected test year.

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 2019 projected test year provide a reasonable basis for establishing rates in this case?

A. Yes, it does. The COSS for the 2019 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 Stocking.

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	)	Case No. U-20276
	)	

DIRECT TESTIMONY AND EXHIBITS OF

ERIC W. STOCKING

FOR

UPPER PENINSULA POWER COMPANY

September 21, 2018

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 describe your job responsibilities.

A. I am UPPCO's Rate Analyst within the Regulatory Affairs department. My responsibilities in this role include analytical support of a wide variety of issues touching several aspects of the business, including power supply, resource planning, cost of service and rate design, sales and peak demand forecasting, and Renewable Portfolio Standard ("RPS") compliance 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") Staff as an Economic Analyst in the Generation and Certificate 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 & 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 moved into my current role at UPPCO.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC")?

A. Yes. I have provided testimony in several cases before the Commission, both on behalf of the MPSC Staff as well as UPPCO.

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:

1. The development of the Company's current electric sales and peak demand forecast for the period 2019 – 2025.
2. The Company's proposed rate design, pursuant to the results of the Company's Cost of Service Study ("COSS") sponsored by Company Witness Haehnel.
3. Propose the establishment of a new Power Supply Cost Recovery ("PSCR") Base Rate for the purpose of determining the PSCR factors for future recovery of power supply costs through the PSCR process.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following Exhibits:

I. Exhibit A-5, Schedule E1.1:

II. Exhibit A-5, Schedule E1.2:

III. Exhibit A-5, Schedule E1.3:

IV. Exhibit A-15, Schedule E1.1:

V. Exhibit A-15, Schedule E1.2:

VI. Exhibit A-15, Schedule E1.3:

VII. Exhibit A-15, Schedule E2.1:

VIII. Exhibit A-15, Schedule E2.2:

IX. Exhibit A-16, Schedule F2:

X. Exhibit A-16, Schedule F3:

XI. Exhibit A-16, Schedule F4:

XII. Exhibit A-16, Schedule F5:

XIII. Exhibit A-42, Schedule F1:

XIV. Exhibit A-42, Schedule F2:

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

A. Yes, they were.

1. 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 2013 – 2017. 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 2013 – 2017. This exhibit also summarizes company use and distribution loss kilowatt-hours (“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 2013 – 2017.

Q. Please describe Exhibit A-15, Schedules E1.1, E1.2, E1.3, E2.1, and E.2.2.

A. Exhibit A-15, Schedule E1.1 provides an annual summary of projected service area sales by major customer class for the years 2019 – 2023. This exhibit also summarizes company use and distribution loss kilowatt-hours (“kWh”), and sums to total system output.

Exhibit A-15, Schedule E1.2 provides an annual summary of projected bundled service sales by major customer class for the years 2019 – 2023. This exhibit also summarizes company use and distribution loss kilowatt-hours (“kWh”), and sums to total system output.

Exhibit A-15, Schedule E1.2 provides an annual summary of projected AES sales by major customer class for the years 2019 – 2023.

Exhibit A-15, Schedule E2.1, page 1 provides an annual summary of total service area system output, maximum demand, and average system load factor for years 2013 – 2023.

Exhibit A-15, Schedule E2.2 provides an annual summary of bundled system output, maximum demand, and average system load factor for years 2013 – 2023.

Q. Please explain how the Company's 2019 sales forecast was developed.

A. Given recent actions taken to combine the Integrated and Iron River systems into combined tariff units, both systems were forecasted in tandem. The Residential forecast utilizes two regression models, a monthly customer count projection and a monthly use-per-customer model. Both models include seasonal customers and sales. The historical period utilized as a basis for the projection is January 1, 2013 through December 31, 2017. The customer count projection is based on a regression analysis of the historical monthly trend in the number of residential customers. The use-per-customer forecast is based on a regression model, utilizing seasonal, weather related, and autoregressive variables to project average residential customer usage. The product of the customer forecast and the use-per-customer forecast yields the values depicted in Exhibit A-15, Schedule E1.2.

The Commercial forecast utilizes two regression models, a customer model and a use-per-customer model. The models use historical data from January 2013 – December 2017, and exclude Company use sales. The customer forecast is based on a regression analysis of the historical monthly trend in the number of commercial customers within the service territory, excluding those served by an AES. The use-per-customer model is based on a regression model, utilizing seasonal, weather-related, and autoregressive variables to project average commercial customer usage. The product of the customer forecast and the use-per-customer forecast yields the commercial class values depicted in Exhibit A-15, Schedule E1.2.

The Industrial forecast utilizes a use-per-customer regression model. The model uses historical data from January 2013 – December 2017. The customer forecast is based on the historical trend in the number of commercial customers within the service territory, excluding those served by an AES. The use-per-customer model is based on a regression model, utilizing seasonal, weather-related, Producer Price Index, and autoregressive variables to project average commercial customer usage. The product of the customer forecast and the use-per-customer forecast yields the Industrial class values depicted in Exhibit A-15, Schedule E1.2.

Company Use is based on a regression model utilizing historical Company Use sales as a percentage of total sales.

Given the Company's intent to embark on a large-scale replacement of its existing Sodium Vapor and Metal Halide lighting fixtures to LED, as evidenced by its filing made in Case No. U-20168, I determined that it was not reasonable to project future lighting sales based on a regression analysis of relatively static historical usage levels. 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.

By applying the detailed fixture replacement plan that is set to commence over the next three years, I developed a year-over-year savings profile and applied it to known actual 2017 lighting sales volumes. This savings profile is applied for each of the three years in which UPPCO intends to undertake this large-scale conversion to LED public lighting, and reflects the savings that will ultimately be realized by this customer class.

Q. How did the Company project total AES customer sales throughout the forecast period?

A. Since the Company has reached its ten percent cap on retail choice customer participation, UPPCO assumes that total AES sales and demand will remain static at actual 2017 levels throughout the forecast period.

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 demand forecast was developed for the 2019 test year.

A. Peak demand is forecasted using a regression analysis of historical peak kilowatt ("kW") to monthly kilowatt-hour ("kWh") sales, along with weather and seasonal explanatory variables.

Q. Please explain the procedures used to develop fixed charge counts for the 2019 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 2017 – December 2017. This analysis produced a known and measurable outlook of fixed charge billing determinants for rate schedules A-1, A-2, AH-1, C-1, H-1, P-1, CP-U (Secondary, Primary, and Transmission), WP-3, Z-3, Z-4, SL-5, and SL-

6. The fixed charge billing determinants are assumed to be static between the 2017 historical period and the 2019 test year period.

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 2007 – 2018 as the basis for assumed future weather characteristics utilized in the forecast.

Q. Please provide a comparison of the total 2016 kWh sales projection made in Case No. U-17895 to actual 2016 billed sales.

A. The 2016 sales projection included in U-17895 totaled 905,207,528 kWh, including sales to AES customers and RTMP usage. Actual 2016 billed sales experienced by the Company in 2016 totaled 852,334,976 kWh, including sales to AES customers and RTMP usage, like the 2016 projection. This constitutes a difference of 52,872,552 fewer billed kWh sales in 2016 compared to the projection by which rates were designed.

Q. Please provide a comparison of the total 2017 kWh sales projection made in Case No. U-17895 to actual 2017 billed sales.

A. The 2017 sales projection included in U-17895 totaled 902,559,438 kWh, including sales to AES customers and RTMP usage. Actual 2017 billed sales experienced by the Company in 2017 totaled 823,960,404 kWh, including sales to AES customers and RTMP usage, like the 2017 projection. This constitutes a difference of 78,599,034 fewer billed kWh sales in 2017 compared to the projection made in U-17895.

Q. What was the projected total 2016 sales volume used as the basis for rate design in U-17895?

A. The sales figures utilized to design rates in U-17895 totaled 902,135,641 kWh. This figure is significantly higher then actual billed sales volumes experienced in 2016.

Q. Please describe the Company's kWh sales projection for the 2019 projected test period.

A. As evidenced by Schedule E1.2 of Exhibit A-15, the Company projects a total bundled sales requirement of 532,950,246 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 2019 sales projection utilized as the basis for rate design in this proceeding?

A. As evidenced by Schedule F3 of Exhibit A-16, which I will describe in the rate design section of my testimony, the sales projection used as a basis for rate design in this proceeding totals 817,414,967 kWh. This value includes the total bundled sales figure discussed previously, plus projected sales to AES customers and the RTMP rate schedule.

2. Rate Design

Q. Please describe Exhibit A-16, Schedule F2.

A. Exhibit A-16, Schedule F2 provides a summary of revenues at current and proposed rates for each rate schedule and calculates the net percentage increase (decrease).

Q. Please describe Exhibit A-16, Schedule F3.

A. Exhibit A-16, Schedule F3 provides a detailed summary of proposed rates by rate schedule.

Q. Please describe Exhibit A-16, Schedule F4.

A. Exhibit A-16 (EWS-11) Schedule F4 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.

Q. Please describe Exhibit A-16, Schedule F5.

A. Exhibit A-16, Schedule F5 contains redline versions of the tariff sheets consistent with the Company's proposed rate design.

Q. Does Exhibit A-16, Schedule F5 include a proposed Distributed Generation tariff, consistent with the Commission's direction in MPSC Case No. U-18383?

A. Yes, it does.

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. Proposed Changes to Rate Structure;
2. Allocation of Rate Increases, Informed by the UPPCO COSS;
3. Rate Design for the A-1 Residential Rate Schedule;
4. Rate Design for the A-2 Residential Rate Schedule;
5. Rate Design for the AH-1 Residential Heating Rate Schedule;
6. Rate Design for the C-1 General Service Rate Schedule;
7. Rate Design for the H-1 Commercial Heating Rate Schedule;
8. Rate Design for the P-1 Light and Power Rate Schedule;
9. Rate Design for the CP-U Rate Schedule;
10. Rate Design for the WP-3 Rate Schedule;
11. Rate Design for the RTMP Rate Schedule;
12. Rate Design for the SL-3, SL-5, & SL-6 Rate Schedule;
13. Rate Design for the Z-3 & Z-4 Rate Schedule;

Q. What Rate Structure changes are you proposing?

A. The Company proposes to combine rate schedules A-1 and A-2 in this proceeding. Both rate schedules provide service to Residential customers in single family (or duplex/apartment) dwellings using electric service for domestic purposes. Both rate schedules include identical riders for Seasonal, Seasonal with electric water-heating, and non-seasonal electric water-heating customers. The only difference between rate schedules A-1 and A-2 is geographic location; A-1 customers reside within the Company's Integrated district, while A-2 customers reside within the Company's Iron River district. Absent any significant difference in the way A-1 and A-2 customers take service, or significant variation in cost to provide service to these customers, the Company does not find any compelling reason to maintain separate rate schedules for these classes. For the purposes of rate design in this proceeding, the proposed rates for schedules A-1 and A-2 are equivalent.

Consistent with the reasons noted above for combining rate schedules A-1 and A-2, the Company proposes to combine rate schedules Z-3 and Z-4 in this proceeding. These schedules govern the dusk to dawn outdoor security lighting service for the Integrated and Iron River districts, respectively. For the purposes of rate design in this proceeding, the proposed rates for schedules Z-3 and Z-4 are equivalent.

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 Haehnel.

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 should 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.

Lastly, rate design should reflect cost of service to the extent practical.

Q. Please describe the process by which the revenue credits listed on Exhibit A-11 A1 are 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 revenue credit of ($2,584,802) shown on Line 18, and the credit of ($694,563) shown on Line 22 of Exhibit A-11 A1. Therefore, these credits 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 A1.

The Company suggests that these credits be applied to the rate design calculation in a strategic manner, with priority given to rate schedules shown by the COSS to require a significant increase from present rates to collect required revenue.

Q. Do UPPCO's proposed rates eliminate cross-subsidization between rate schedules?

A. No, they do not. As evidenced by the results of the UPPCO COSS, there are several instances within rate groupings whereby the COSS model indicates that one rate schedule requires a significant increase to required revenues, while similar classes require a modest increase. For example, the COSS indicates that Residential customers (Rate Schedules A-1, A-2, and AH-1) require a 4.83% increase to required revenues, on average. The percentage increases by rate schedule are 3.31%, 4.58%, and 18.16% for those three schedules, respectively. In this and other similar instances, the Company has identified the relationship between customers within the 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 a significant rate event 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.

A. As evidenced by page 7 of Exhibit A-16, Schedule F1 presented by Company witness Haehnel, the current rate levels within the A-1 schedule are forecasted to under-recover the revenues required for this rate schedule by 3.32%. UPPCO's proposed rate design for A-1 derives a Service Charge of $25.00 per month, and a total volumetric energy rate of $0.18506 / kWh. The details related to the proposed rate design calculation for the A-1 schedule are shown in Exhibit A-16, Schedule F3.

Q. Please describe UPPCO's proposed rate design for the A-2 rate schedule.

A. As evidenced by page 7 of Exhibit A-16, Schedule F1, the current rate levels within the A-2 schedule are forecasted to under-recover the revenue requirement for this rate schedule by 4.58%. UPPCO's proposed rate design for A-2 derives a Service Charge of $25.00 per month, and total energy rate of $0.18506 / kWh. For purposes of this filing, the Company proposes to combine the Integrated (A-1) and Iron River district (A-2) residential schedules into one, with equivalent rates. The details related to the proposed rate design calculation for the A-2 schedule are shown in Exhibit A-16, Schedule F3.

Q. Please describe UPPCO's proposed rate design for the AH-1 rate schedule.

A. As evidenced by page 7 of Exhibit A-16, Schedule F1, the current rate levels within the AH-1 schedule are forecasted to under-recover the revenue requirement for this rate schedule by 18.11%. UPPCO's proposed rate design for AH-1 derives a Service Charge of $25.00 per month, total energy rate of

$0.18506 for June – September, a total energy rate of $0.18506 for all kWh less than 500 kWh during the heating season, and a total energy rate of $0.13308 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-16, Schedule F3.

Q. Were rate schedules A-1, A-2, and AH-1 solved concurrently, as described above?

A. Yes, they were.

Q. Please describe the relationship assumed between A-1, A-2, and AH-1 used to design rates for these three categories concurrently.

A. A-1, A-2, 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 customer 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.

Q. What is the Company's justification regarding the increase to the Service Charge?

A. Electric utilities generally have high fixed costs to provide basic services to customers, regardless of the amount of consumption that a customer may use. These fixed costs do not vary with the amount of electricity that a customer may use. Furthermore, an increased service charge to residential customers is supported by the Company's COSS, as evidenced by page 162 of Exhibit A-16, Schedule F1.

Q. Please describe UPPCO's proposed rate design for the C-1 rate schedule.

A. As evidenced by page 7 of Exhibit A-16, Schedule F1, the current rate levels within the C-1 schedule are forecasted to under-recover the revenue requirement for this rate schedule by 5.53%. UPPCO's proposed rate design for C-1 derives a Service Charge of $50.00, and a total energy rate of $0.17189 per kWh. The proposed telemetering charge for AES customers is $32.88 per month, consistent with the actual costs related to UPPCO providing this service to AES customers. The details related to the proposed rate design calculation for the C-1 schedule are shown in Exhibit A-16, Schedule F3.

Q. Please describe the basis for the Company's proposed telemetering charge.

A. Per the Company's current vendor agreements related to remote meter reading of AES (and other large industrial customers), UPPCO incurs a cost of \$15.00/month/meter, paid to the vendor, to read the meters. UPPCO incurs a cost of \$12.00/month/meter, paid to the vendor, for access to the web data portal. This fee allows both UPPCO, customers, and Suppliers to view the customer's 15-minute interval usage data via a web portal. Additionally, UPPCO incurs an average monthly cost of \$1,200.00 related to wireless communication services that is attributable to the 204 total interval meters currently in service. The cost of wireless communication services equates to a cost of (\$1,200 / 204) = \$5.88/month/meter. The telemetering charge proposed in this proceeding equals the sum of these monthly per-meter costs: (\$15.00 + \$12.00 + \$5.88) = \$32.88/month/meter.

Q. Please describe UPPCO's proposed rate design for the H-1 rate schedule.

A. As evidenced by page 7 of Exhibit A-16, Schedule F1, the current rate levels within the H-1 schedule are forecasted to under-recover the revenue requirement for this rate schedule by 23.75%. UPPCO's proposed rate design for H-1 derives a Service Charge of \$50.00 per month, a total energy rate of \$0.17189 per kWh for June – September, a total energy rate of \$0.17189 for all kWh less than 1,000 kWh during the heating season, and a total energy rate of \$0.13227 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.

Q. Please describe UPPCO's proposed rate design for the P-1 rate schedule.

A. As evidenced by page 7 of Exhibit A-16, Schedule F1, the current rate levels within the P-1 schedule are forecasted to under-recover the revenue requirement for this rate schedule by 60.33%. UPPCO's proposed rate design for P-1 derives a Service Charge of $60.00 per month, total demand charges of $15.35 per kW, and a total Energy Charge of $0.09524 per kWh. The details related to the proposed rate design calculation for the P-1 schedule are shown in Exhibit A-16, Schedule F3.

Q Were rate schedules C-1, H-1, and P-1 solved concurrently to mitigate the significant rate increase to recover required revenues experienced by H-1 and P-1?

A. Yes, they were.

Q. Was any amount of the $3.28M revenue credit applied to the Commercial class solution (C-1, H-1, and P-1)?

A. Yes, ($2,285,278.74) was applied to the Commercial class solution to offset additional required revenues from the class.

Q. Please describe UPPCO's proposed rate design for the CP-U rate schedule.

A. As evidenced by page 9 of Exhibit A-16, Schedule F1, the current rate levels within the CP-U schedule are forecasted to under-recover the revenue requirement for this rate schedule by 43.45% in CP-U Secondary, 47.35% in CP-U Primary, and 20.84% in CP-U Transmission.

UPPCO's proposed rate design for CP-U Secondary derives a Service Charge of $350.00 per month, total firm demand charges of $13.98 per kW, total interruptible demand charges of $6.48 per kW, total customer demand charge of $5.09 per kW, an on-peak energy charge of $0.06149 per kWh, and an off-peak energy charge of $0.03998 per kWh.

UPPCO's proposed rate design for CP-U Primary derives a Service Charge of $425.00 per month, total firm demand charges of $13.70 per kW, total interruptible demand charges of $6.20 per kW, total customer demand charge of $3.87 per kW, an on-peak energy charge of $0.05927 per kWh, and an off-peak energy charge of $0.03853 per kWh.

UPPCO's proposed rate design for CP-U Transmission derives a Service Charge of $850.00 per month, total firm demand charges of $13.51 per kW, total interruptible demand charges of $6.01 per kW, total substation transformer capacity charge of $1.95 per kVA, an on-peak energy charge of $0.05710 per kWh, and an off-peak energy charge of $0.03712 per kWh. The details related to the proposed rate design calculation for the CP-U schedule are shown in Exhibit A-16, Schedule F3.

Q. Was any amount of the $3.28M revenue credit applied to the CP-U rate schedule rate design proposal?

A. Yes, ($994,086.49) was applied to the CP-U schedule solution to offset additional required revenues from the class.

Q. Please describe UPPCO's proposed rate design for the WP-3 rate schedule.

A. As evidenced by page 9 of Exhibit A-16, Schedule F1, the current rate levels within the WP-3 rate schedule are forecasted to under-recover the revenue requirement for this schedule by 19.01%. UPPCO's proposed rate design for the WP-3 schedule derives a Service Charge of $850.00 per month, total firm demand charges of $13.03 per kW, total interruptible demand charges of $5.53 per kW, substation transformer capacity of $0.87 per KVA, total on-peak energy charges of $0.05710 per kWh, and total off-peak energy charges of $0.03712 per kWh. The details related to the proposed rate design calculation for the WP-3 schedule are shown in Exhibit A-16, Schedule F3.

Q. Please describe UPPCO's proposed rate design for the RTMP rate schedule.

A. As evidenced by page 9 of Exhibit A-16, Schedule F1, the current rate levels within the RTMP rate schedule are forecasted to under-recover the revenue requirement for this schedule by 63.03%. UPPCO's proposed rate design for the RTMP schedule derives a monthly customer charge of $15,224.08 per month, a demand charge of $0.71 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-16, Schedule F3.

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's proposed rate design incorporates several reductions to the monthly lamp charge rates and energy rates, intended to recover the class required revenues per the UPPCO COSS. Given the Company's intent to embark on a large-scale replacement of Sodium Vapor lighting fixtures with LED, the lighting rates proposed in this proceeding assume that all existing traditional fixtures have been replaced with equivalent LED fixtures. Furthermore, the proposed rate design assumes the combination of Z-3 and Z-4 (Integrated and Iron River District Outdoor Lighting) rate schedules. The details related to the proposed rate design calculation for the Streel Lighting and Outdoor Lighting schedules are shown in Exhibit A-16, Schedule F3.

Q. What is the bill impact to an average Residential customer as a result of the Company's proposed rate design in this proceeding?

A. As evidenced by Schedule F4 of Exhibit A-16, a residential customer, previously taking service under the A-1 tariff, consuming 500 kWh per month will receive a monthly bill of $117.53. This constitutes an increase of $3.12, or 2.73% when compared to present revenues.

Q. What is the bill impact to an average small Commercial customer as a result of the Company's proposed rate design in this proceeding?

A. As evidenced by Schedule F4 of Exhibit A-16, a C-1 customer consuming 2,500 kWh per month will receive a monthly bill of $479.71. This constitutes an increase of $90.06, or 23.11% 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?

A. As evidenced by Schedule F4 of Exhibit A-16, a P-1 customer consuming 20,000 kWh, and 55 kW per month will receive a monthly bill of $2,809.08. This constitutes an increase of $326.52, or 13.15% compared to a similarly calculated bill at current rates. For reference, the outcome of U-17895 calculated an average bill of $2,815.08 for a CP-U customer with the same energy and demand requirements. This constitutes a decrease of $6.48, or -0.23% when compared to the 2016 rate case outcome.

Q. What is the bill impact to an average Industrial customer as a result of the Company's proposed rate design in this proceeding?

A. As evidenced by Schedule F4 of Exhibit A-16, a CP-U customer consuming 480,000 kWh, and 1,260 kW per month will receive a monthly bill of $57,212.95. This constitutes an increase of $9,892.46, or 20.91% compared to a similarly calculated bill at current rates. For reference, the outcome of U-17895 calculated an average bill of $60,667.63 for a CP-U customer with the same energy and demand requirements. This constitutes a decrease of $3,454.68, or -5.69% when compared to the 2016 rate case outcome.

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?

A. As evidenced by Schedule F4 of Exhibit A-16, an SL-6 customer with one 100-Watt LED fixture, one pole, and one span of conductor will receive a monthly bill of $20.64. This constitutes a decrease of $5.21, or -20.16%.

Q. Are the proposed rates in this proceeding designed to collect the required revenues indicated by the Company's COSS, to the extent practical?

A. Yes.

<u>3. Establishment of PSCR Base</u>

Q. Please describe Exhibit A-42.

A. Lines 1 through 30 of Exhibit A-42 outline the following as forecasted for the UPPCO system for the 2019 test year:

1. The forecasted Net PSCR Costs, which are equal to the PSCR costs of generation, purchases, and transmission less
    a. Opportunity sales revenues,
    b. Real Time Market Price Tariff ("RTMP") sales revenues,

    c. RTMP transmission revenues,
    d. Capacity sales revenue,
    e. Renewable Energy Certificate ("REC") sales revenue, and
    f. Ancillary services revenues.

2. Megawatt hours of Generation plus purchased power less,
    a. Opportunity sales and
    b. RTMP sales,

3. The MWhs of System Requirement Sales subject to a PSCR Factor,

4. The average PSCR cost per MWh,

5. The current PSCR Base Rate,

6. The current PSCR Loss Factor, and

7. The resulting PSCR Factor;

And the current PSCR Base Rate and PSCR Loss Factors that were established in UPPCO's last general base rate proceeding, Case No. U-17895.

Lines 31 through 60 of Exhibit A-42 show:

1. The forecasted Net PSCR Costs, which are equal to the PSCR costs of generation, purchases, and transmission less
    a. Opportunity sales revenues,
    b. RTMP sales revenues,
    c. RTMP transmission revenues,
    d. Capacity sales revenues,
    e. REC sales revenues, and
    f. Ancillary services revenues.

2. Megawatt hours of Generation plus purchased power less,
    a. Opportunity sales, and
    b. RTMP sales,

3. The MWhs of System Requirement Sales subject to a PSCR Factor,

4. The average PSCR cost per MWh,

5. The new proposed PSCR Base Rate, and

6. The new proposed PSCR Loss Factor

as forecasted for the UPPCO system for the 2019 test year.

Q. Please describe Exhibit A-42, Schedule F2.

A. Schedule F2 of Exhibit A-42, pages 1 and 2 are the proposed tariff sheets reflecting the proposed PSCR Base Rate, PSCR Loss Factor, and the resulting PSCR factor.

UPPCO proposes to implement the new PSCR Base Rate starting with the beginning of the first business month after the effective date of new base rates in this case.

UPPCO proposes to implement a revised PSCR Factor starting with the first business month after the effective date of new base rates established in this proceeding, consistent with the approved PSCR Base Rate and Loss Factor, and based on the PSCR plan sales and power supply costs used to establish the PSCR factor at that time.

Q. What is UPPCO's current estimate of the PSCR Factor for 2019?

A. As shown on line 28 of Exhibit A-42, UPPCO has forecasted a PSCR Factor of negative ($17.59)/MWh for 2019 based on the current PSCR Base Rate, the current PSCR Loss Factor, and the forecast of fuel and purchased power costs in this proceeding.

Q. How does UPPCO propose to determine the new PSCR Base Rate for the

UPPCO system?

A. UPPCO proposes to establish a new PSCR Base Rate to be equal to the Net PSCR Costs divided by the MWhs of generation plus purchased power less:

a. Opportunity sales and
b. RTMP sales

as forecasted for the UPPCO system for the 2019 test year. Based on the net PSCR costs forecasted for 2019, the proposed PSCR Base Rate will yield an expected PSCR Factor of zero.

Q. What is the current PSCR Base Rate for the UPPCO system?

A. The current PSCR Base Rate for the UPPCO system is $58.57/MWh as shown on line 24 of Exhibit A-42.

Q. What is the proposed new PSCR Base Rate for the UPPCO system?

A. The proposed new PSCR Base Rate for the UPPCO system is $42.01/MWh as shown on line 54 of Exhibit A-42.

Q. What is UPPCO's proposed new PSCR Factor for 2019?

A. Based on UPPCO's proposal to establish a new PSCR Base Rate based on the net PSCR costs forecasted for 2019, the proposed PSCR Factor is $0.00/MWh, as shown on line 58 of Exhibit A-42.

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 retail electric rates.	)	Case No. U-20276
	)	

DIRECT TESTIMONY AND EXHIBITS OF

KEITH E. MOYLE

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

September 21, 2018

QUALIFICATIONS

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

A. My name is Keith E. Moyle. My business address is 1002 Harbor Hills Drive, Marquette, MI 49855. I am the Chief Operating Officer ("COO") 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 am a licensed Professional Engineer in the State of Wisconsin. I began my career with Wisconsin Public Service Corporation ("WPS Corp ") in March 1985 in the Distribution Engineering Department, as an Electrical Engineer. Thereafter, I worked for WPS Corp in various positions including, Division Electrical Engineer, Gas & Electric Supervisor, District Operations Manager, and Fleet Manager. In December 2005, I transferred to UPPCO as General Manager. My current position as UPPCO's COO began in August 2014. Each of these line items is forecasted based on historical values and current information known about that line item.

PURPOSE OF TESTIMONY

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. What exhibits are you describing in this proceeding?

A. I am describing portions of the following exhibits that are sponsored in the testimony of Company Witness Kates:

1. Schedule B5.1 (Pages 1 & 2) of Exhibit A-12
2. Schedule B5.4 (Page 1) of Exhibit A-12
3. Schedule B5.6 of Exhibit A-12

Q. Please describe Schedule B5.1 (Pages 1 & 2) of Exhibit A-12.

A. Schedule B5.1 (Pages 1 & 2) of Exhibit A-12 provides a summary of the Company's actual and projected capital expenditures by power generation by business driver and facility for each year from 2017 through 2019. As demonstrated on line 7 of Page 1, actual 2017 capital expenditures for power generation totaled $560,486. Also, projected 2018 and 2019 capital expenditures total $1,608,448 and $1,310,000, respectively. The same values are broken down by production facility on line 17 of Page 2 of this same exhibit.

Q. Please describe Schedule B5.4 of Exhibit A-12.

A. Schedule B5.4 of Exhibit A-12 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 from 2017 through 2019. Each of these line items is forecasted based on historical values and current information known about that line item.

As demonstrated on line 7, actual 2017 capital expenditures for distribution totaled $7,822,745. Projected 2018 and 2019 capital expenditures for distribution total $8,019,364 and $8,030,000 respectively. Later in my testimony I will speak to 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 on line 12, actual 2017 capital expenditures for substation totaled $2,385,328. Projected 2018 and 2019 capital expenditures for substation total $1,155,000 and $2,330,578 respectively.

In total, as demonstrated on line 14, actual 2017 capital expenditures for distribution and substation totaled $10,208,073. Projected 2018 and 2019 capital expenditures for distribution and substation total $9,174,364 and $10,360,578 respectively.

Q. Please describe Schedule B5.6 of Exhibit A-12.

A. Schedule B5.6 of Exhibit A-12 provides a summary of the Company's actual and projected capital expenditures for corporate from 2017 through 2019. The items on lines 3 and 4 covering Fleet and Facility expenditures, respectively, are forecasted based on historical values and current information known about those line items. As demonstrated on lines 3 and 4, actual 2017 capital expenditures for Fleet and Facility totaled $1,278,198 and $608,662, respectively. Also, projected 2018 and 2019 capital expenditures for Fleet total $1,352,950 and $1,420,598, as evidenced on line 3. Capital expenditures projected for Facilities in 2018 and 2019 are $2,300,000 and $1,208,000, as evidenced on line 4.

Q. What exhibits are you fully sponsoring in this proceeding?

A. I am fully sponsoring the following exhibits, which were prepared by me or under my direction.

1. Exhibit No. A-27, UPPCO Capital Expenditures (CAPEX) by Business Line
2. Exhibit No. A-28, UPPCO Facility CAPEX
3. Exhibit No. A-29, UPPCO Substation CAPEX
4. Exhibit No. A-30, UPPCO Generation CAPEX
5. Exhibit No. A-31, UPPCO Distribution Reliability CAPEX
6. Exhibit No. A-32, 2013-2017 Reliability Indices (as filed)
7. Exhibit No. A-33, 2013-2017 Reliability Indices (as revised)
8. Exhibit No. A-34, Major Event Days
9. Exhibit No. A-35, Weather Outages by Cause
10. Exhibit No. A-36, 2015-2017 Pole Inspections
11. Exhibit No. A-37, 2015-2017 Underground Inspections
12. Exhibit No. A-38, 2019-2020 System Hardening & Reliability Projects
13. Exhibit No. A-39, 6 Year Distribution Line Clearance Program

Q. Please identify and describe your fully-sponsored supporting exhibits related to UPPCO's 2018 through 2019 projected capital expenditures.

A. Below is a description of the exhibits.

Exhibit A-27, UPPCO Capital Expenditures (CAPEX) by Business Line, provides a summary level depiction of the Company's actual and projected expenditures by business driver n from 2016 through 2019. Each of these line items is forecasted based on historical values and current information known about that line item.

Exhibit A-28, UPPCO Facility CAPEX identifies all the facility projects for 2018 and the 2019 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 on line 7 of this exhibit, UPPCO's 2018 capital spend is estimated at \$2,300,000, and UPPCO's 2019 projected capital spend is \$1,208,000.

Exhibit A-29, UPPCO Substation CAPEX, identifies all the substation projects for 2018 and the 2019 projected test year, broken down into blanket/routine totals for projects less than \$100,000 and individual totals for substation projects greater than \$100,000. As demonstrated on line 15 of this exhibit, UPPCO's 2018 capital spend is estimated at \$1,155,000, and UPPCO's 2019 projected capital spend is \$2,330,578.

Exhibit A-30, UPPCO Generation CAPEX, identifies all the projects for 2018 and the 2019 projected test year broken down into blanket/routine totals for projects less than \$100,000 and individual totals for generation projects greater than \$100,000. As demonstrated on line 7 of this exhibit, UPPCO's 2018 capital spend is estimated at \$1,608,448, and UPPCO's 2019 projected capital spend is \$1,310,000.

Exhibit A-31, UPPCO Distribution Reliability CAPEX, identifies all the projects in the improved reliability and load growth business driver category for 2018 and the 2019 projected test year broken down into blanket/routine totals for projects less than $50,000 and individual totals for projects greater than $50,000. This exhibit also includes intended 2020 capital projects. The purpose of including UPPCO's intended 2020 distribution capital projects is that due to resource planning and optimization, UPPCO may decide to push and or pull certain projects from 2020 into 2019, and vice versa. UPPCO intends to manage to the yearly summed distribution capital expenditure values as demonstrated on line 48, which for 2018 is estimated at $4,990,000, and for 2019 is projected at $4,725,000. Later in my testimony, I will more fully explain UPPCO's approach to managing distribution system reliability, including the identification and prioritization of distribution system hardening and reliability projects.

MANAGING UPPCO'S DISTRIBUTION SYSTEM RELIABILITY

System Conditions

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

A. My testimony is organized as follows:

1. Distribution System Conditions
2. Reliability Metrics and System Goals
3. Local System Load Forecasts
4. Maintenance and Upgrade Plans
5. Capital Expenditure Decision Criterion
6. Customer Value Analyses

7. List of Capital Projects

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

A. UPPCO serves approximately 54,000 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 2,200 miles of primary, 640 miles of secondary, and 560 miles of service line. The underground lines consist of approximately 720 miles of primary, 40 miles of secondary, and 330 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 13 customers per line mile of distribution system over a heavily wooded service territory.

UPPCO's overhead system is supported primarily on wood poles that have an average age of 35 years. The expected life of a typical utility pole is 40 years. Currently, 25.7% of UPPCO's poles are of the 1970-1975 vintage, making those poles 43-48 years old, at least three years beyond their 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. Cable of this vintage is more prone to faults, and its neutral conductors that can corrode, causing a safety hazard and overcurrent protection issues.

Reliability Metrics & Goals

Q. Please provide an overview of UPPCO's reliability metrics and goals.

A. In late 2013, the State of Michigan set aggressive goals for reliability in Michigan for a "no regrets" energy future with an objective of Michigan becoming a leader in reliability by reducing both the average number of outages and their length. Specifically, the State declared that Michiganders should experience less than one outage per year, and the aggregate outage duration should be less than 2½ hours.[1] Like the State, UPPCO is also trying to improve the customer experience.

For reliability metrics, since 2012 UPPCO has used the Institute of Electrical and Electronic Engineers' ("IEEE") Guide for Electric Distribution Reliability Indices, Standard 1366 ("IEEE Standard 1366"). Standard 1366 includes three indices, SAIDI ("System Average Interruption Duration Index"), SAIFI ("System Average Interruption Frequency Index"), and CAIDI ("Customer Average Interruption Duration Index"), that are often used to compare performance among utilities. The State's reliability goals announced in 2013 equate to a SAIDI of less than 150 minutes per year and a SAIFI of no more than 1 event per year.

Exhibit A-32, 2013 – 2017 Reliability Indices (as filed), filed with the MPSC on March 28, 2018, shows UPPCO's 5-year reliability data for All Weather conditions and Excluding Major Event Days ("MEDs").. Please note, for 2013-2016, UPPCO's reliability data included transmission-caused outages. In 2017, UPPCO made the decision to eliminate transmission-caused outages from its reliability indices calculations based on

[1] "A Special Message from Gov. Rick Snyder, Ensuring Affordable, Reliable, and Environmentally Protective Energy for Michigan's Future," March 13, 2015.

language in IEEE 1366-2012, Section 5.2, which states that “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”), a separate utility, so outages caused by loss of transmission should not be included in UPPCO-specific reliability indices.

Exhibit A-33, 2013 – 2017 Reliability Indices (as revised) shows UPPCO’s revised 5-year reliability data reflecting UPPCO’s decision to remove transmission-caused outages from its reliability indices calculations.. UPPCO’s SAIDI was 176 minutes and SAIFI was 1.2 events per average UPPCO customer, excluding major event days (“MEDs”), which is greater than the State’s goals. Including MEDs, in 2017 UPPCO’s SAIDI was 573 minutes, which is nearly four times the State’s goal of 150 minutes, and UPPCO’s SAIFI was 2.1 events per average UPPCO, which is more than two times the State’s goal of 1 event per customer.

As evidenced in Exhibit A-34, Major Event Days (“MED”), UPPCO represents the Threshold for a Major Event Day (“TMED”) from 2013-2017 as well as the number of MEDs per year. Please note that there was only one MED in 2013, 2014, and 2015, but three in 2016 and five in 2017. 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 are 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 2013 data to 2017 and excluding MEDs, the data indicates that UPPCO's reliability is improving, and its metrics are on a downward trend. This, in part, is due to UPPCO's accelerated line clearance program over the time period of 2014-2017. The decline has not been a straight line over this period, however, as there was an increase in 2016 and 2017 due to the impact of major storms on the indices.

Exhibit A-35, Weather Outages by Cause, depicts UPPCO's 5-year average from 2013-2017 of all the weather outages by cause.

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. The 10-year average for UPPCO's system load growth from 2008 to 2017 was -0.4%.

Maintenance & Upgrade Plans

Q. Please provide an overview of UPPCO's maintenance and upgrade plans.

A. Strong winds predominantly cause 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 goes out regularly for competitive bid, it has detailed specifications for line clearance that is contractors must follow, which includes 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. As discussed further below, UPPCO's line clearance has been improving for many years, and the Company has recently completed its previously approved accelerated line clearance project which ran from 2014 to 2017. With the completion of this accelerated program, the Company will now revert to a 6-year cycle for its system. I provide further information on this change later in my testimony.

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

Q. Please provide a more detailed description of UPPCO's storm hardening practices.

A. The following provides additional background on each of the practices listed above:

1. 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 a good 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. Later in my testimony, I will further explain UPPCO's line clearance program.
2. UPPCO has also implemented a comprehensive overhead facilities inspections and treatment program. The eplacement of poles in poor condition and the treating of ground lines on otherwise sound poles eliminate 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, such as pole treatment at the ground line, repairing grounds, and installing guy markers, are identified and repaired during the

inspection process,while other identified “danger and reject” poles are scheduled for replacement within a year after the inspection results are received. From 2015 to 2017, 4.2% of the inspected poles were classified as danger or reject poles. A record of UPPCO’s pole inspection history is evidenced in Exhibit A-36, 2015 – 2017 Pole Inspections. As seen in this table, the 3-year average cost for the professional overhead system inspection and pole treatment was approximately $157,000 per year, or roughly $23 per pole. The inspection program is an on-going maintenance activity which needs to be continued.

3. An underground inspection program can also identify issues before they become outages by identifying equipment in poor condition, undermined or tilting equipment, and other safety issues. UPPCO performs a visual inspection 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 following construction season after the facilities were put in the ground. A record of UPPCO’s underground inspection history is evidenced in Exhibit A-37, 2015 – 2017 Underground Inspections. As seen in this table, the 3-year average cost for the professional underground system inspection was approximately $59,000, or roughly $54 per cabinet. This on-going maintenance activity needs to be continued.

4. Selective rerouting of overhead lines to underground in areas with a high tree density, prone to frequent tree/storm related outages, or with limited accessibility

is another manner 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.

5. Replacing poles with taller and stronger poles is also an effective system hardening process. 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.

6. A thorough shared facilities program ensures that foreign attachments are accounted for and included in pole loading calculations. Existing facilities are brought to current NESC standards when new attachments are requested, and 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.

7. UPPCO also 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, such as continuing the line clearance program and rerouting overhead lines to underground, help crews to better access outage locations.

   Another reliability consideration is to possibly reroute 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 attempting to identify and access outage locations and to make necessary repairs.

   Another method to increase the flexibility, and therefore reliability, of the distribution system is to add switching capability. 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. The crews, then close a normally open point to restore power to customers that otherwise would have been subject to an outage until the system can be repaired. The practice of switching to partially restore service significantly reduces the duration of the outage and improves SAIDI metrics.

These design considerations are taken into account as part of the capital expenditure budget and prioritization process.

8. 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 provides the ability to dispatch outages more quickly to the correct outage location. Additionally, UPPCO is planning to implement Automated Meter Infrastructure ("AMI"), which will provide the ability to know exactly which customers. Also, this will aid in diagnosing system issues as well as increase efficiencies in dispatching resources. Company Witness's Brynick and Haehnel provide supporting testimony regarding this benefit. This will aid in diagnosing system issues as well as increase the efficiency in which lineman are dispatched to implement repairs.

   b. Reverse-sensing voltage regulators have also been installed in specific locations. Those regulators can operate in reverse load flow conditions 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 technologythat 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 is currently installing a partial DA project at a very remote substation fed by a radial transmission line. For that location, the line crew must travel a long distance to the substation to isolate and switch to a back-up feeder. UPPCO is adding SCADA-controlled switches to tie the feeders together to the back-up source. Although backup switching will not be automatic, it will reduce 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 its distribution system.

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 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 number of outage events) with the worst feeder in each category getting the maximum number of points. UPPCO has 98 feeders in the 5-year data set, so the worst feeder in each category is assigned 98 points and the best feeder assigned 1 pt. The points are added for each of the four measures, and the feeder with the most points is considered the least 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 feeders are inherently large electrical circuits covering an average of over 45 line-miles per feeder, no one project can improve an entire feeder's reliability. The multiple device operations metric can therefore pinpoint where work is needed on a specific feeder to improve reliability.
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. Increasing reliability to provide a better customer experience and to strive towards the State's goals requires additional capital investment for storm hardening. Due to UPPCO's low customer density and miles of line per customer, it is difficult to achieve the State's reliability goals at current investment levels.

UPPCO's distribution projects have historically had a focus on ensuring compliance with Michigan Public Service Commission ("MPSC") standards for distribution system adequacy, safety, and proper voltage, 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 resource age and 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 of one outage per customer per year, lasting no more than 150 minutes.

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 be uncovered requiring reprioritization within a budget year, or even within the 5-year planning horizon as system conditions evolve from year to year.

System Hardening & Reliability Projects

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 2019 projected test year, UPPCO is planning to implement the projects as evidenced in Exhibit A-38, 2019 – 2020 System Hardening and Reliability Projects. UPPCO has also identified its intended capital projects for 2020 as certain projects may get "pushed" and "pulled" between the 2019 and 2020 capital year depending on resource and planning optimization. UPPCO will still however manage to the $3,250,000 total capital expenditure value as demonstrated in Exhibit A-38. The identification of these projects ultimately informs UPPCO's improved reliability and load growth component of the Company's distribution CAPEX plan.

2019 JUST AND REASONABLE

Q. As outlined in your testimony, do you believe the capital projects that constitute UPPCO's 2019 projected test year capital expenditures are just and reasonable?

A. Yes. As evidenced in Exhibit A-27 and Exhibit A-12, the capital spending levels are generally consistent with UPPCO's recent historical data with a modest increasing trend in alignment with Michigan and the Governor's increasing focus on reliability and system hardening. As evidenced in Exhibit A-27 on line 27, column H, UPPCO's 2019 projected capital expenditures excluding special projects is approximately 0.5% more than the two-year average. And, as evidenced in line 27, column J, UPPCO's 2019 projected capital expenditure is approximately 6.3% higher than the three-year average. As demonstrated in my testimony, UPPCO has applied a rigorous approach to identifying and prioritizing its distribution capital projects.

LINE CLEARANCE PROGRAM COMPLIANCE AND AMENDMENTS

A. Please describe UPPCO's line clearance program.

Q. UPPCO has approximately 2,230 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. 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. 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. In accordance with Order Points "K" and "L" of the Commission's order in MPSC Case No. U-17274, has UPPCO successfully completed its directives regarding line clearance?

A. Yes. UPPCO has reported its historical line clearance data from 2014 through 2017 and has cleared at least 1,760 miles on a cumulative basis over this time frame at mandated cost of no less than $3,168,907. Please note, this equates to an average of 440-line miles per year of clearance. From 2014 through 2017, UPPCO cleared the following line miles: 408 (2014), 472 (2015), 475 (2016), and 462 (2017).

Q. In the 2019 projected test year, how many line clearance miles will UPPCO be targeting for its distribution line clearance program?

A. Now that UPPCO's accelerated catch-up program is complete, UPPCO will be trimming 401-line miles per year at a cost of $2,330,500 in the 2019 projected test year as it moves toward a 6 year cycle, as evidenced in Exhibit A-39, 6 Year Distribution Line Clearance Program.

Q. In the 2019 projected test year, what is the value of the forecast adjustment in FERC 580 due to the increase in the years of cycle trim when compared to the 2017 historical test year?

A. The difference in line clearance spend is ($926,707) and is represented as a forecast adjustment in the 2019 projected test year. Please see Exhibit A-39, 6 Year Distribution Line Clearance Program.

CONCLUSION

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.	)	Case No. U-20276
____	)	

DIRECT TESTIMONY AND EXHIBITS OF

JASON BRYNICK

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

September 21, 2018

QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Jason Brynick. My business address is 1002 Harbor Hills Drive, Marquette, MI 49855.

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

A. I am employed by Upper Peninsula Power Company ("UPPCO" or the "Company") as Project Manager.

Q. Briefly describe your education background and employment history.

A. I earned a Bachelor of Science degree from Michigan Technological University in both Civil Engineering and Business Administration in 2004. For the better part of my career I have worked as a senior-level Project Manager in the construction of electric utility and heavy-civil infrastructure projects, such as bridges and tunnels. Along with senior-level Project Management duties I was also heavily involved with our estimating department when bidding large projects in these lines of work. In 2015, I accepted a position as Program Manager, at Google Fiber of Mountain View, CA, overseeing the construction of Google Fiber infrastructure. In 2017, I accepted the position of Project Manager at Upper Peninsula Power Company where I am Project Manager for the AMI Project.

REGULATORY | BACKGROUND

Q. Is UPPCO presenting a business case that outlines its investment in Advanced Metering Infrastructure ("AMI")?

A. Yes.

Q. Please define AMI?

A. Consistent with what was provided in Michigan Public Service Commission ("MPSC" or the "Commission") Case No. U-17000, Staff stated that (1) Advanced Metering Infrastructure (AMI) systems "combine meters with two-way communication capabilities. These systems typically are capable of recording near-real-time data on power consumption and reporting that consumption to the utility at frequencies of an hour or less"[1], and (2) AMI meters are also known as smart meters, and they represent one component of an improved or smart grid.

Q. Explain the relevance of MPSC Order U-17000.

A. On January 12, 2012, the Commission issued an order in MPSC Case No. U-17000. This order directed the utilities to provide information regarding their respective plans for smart meter deployment including proposed costs and benefits, scientific information addressing the safety of smart meter deployment, assurance of customer data privacy and other information. Within the context of this order, Commission Staff prepared a report ("Staff's Report on Advanced Metering Infrastructure ("AMI") and Smart Grid") to the Commissioners on June 29, 2012 that outlined Staff's engagement in a thorough review of resources regarding smart meters culminating in key Staff recommendations regarding AMI.

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[1] Massachusetts Institute of Technology, The Future of the Electric Grid; An Interdisciplinary MIT Study, 2011, p.133. http://web.mit.edu/mitei/research/studies/documents/electric-grid-2011/Electric_Grid_Full_Report.pdf

Q. In the Staff's Report on AMI and Smart Grid, evidenced in Exhibit A-43, MSPC Staff Report U-17000, what were Staff's salient recommendations?

A.

1. Smart meter implementation: Staff acknowledged that smart meters are part of a larger smart grid initiative that have been "endorsed by federal laws and technologies and have been declared to be safe by accredited national agencies and industry councils." (page 3)

2. Opt-out: Staff acknowledged that a minority of customers have expressed concerns about smart meters, and as such, should be allowed to opt-out. Further, Staff believes that the opt-out provision should be based on cost of service principles and be accounted for by either "an additional charge for those customers choosing to opt-out or a discount for those customers with an AMI meter." (page 3)

3. Revised rules and/or tariffs: Staff acknowledges that there should be consideration to ensure "consistent protection of customer privacy and data." (page 3)

4. Smart grid vision: Staff further outlined a Smart Grid Vision to provide a framework for future grid modernization in Michigan. Staff elaborated on the following objectives:

   a. "AMI introduces a communications platform that can support a multitude of smart grid applications resulting in improved efficiency and reliability, as well as increased longevity of Michigan's aging electric infrastructure. When properly designed and implemented, AMI presents a unique opportunity for Michigan ratepayers to take control of their energy consumption and their energy bills." (page 22)

b. "The smart grid will enhance electric service in Michigan. Real time outage identification, through AMI, will result in a quicker response to outage situations. Areas without service can be identified almost immediately and individual customers who are still out after their neighborhood has been restored will be easily located. The smart grid technologies will reduce operations and maintenance costs, primarily through reduced meter reading costs, more accurate billing, reduced outage time and monitoring tools that help the utility anticipate equipment failure. AMI meters, with the use of dynamic and time-of-use rates, can reduce peak demand and increase energy conservation. The result could curtail the need for future capital investment in electrical system capacity and lead to other grid efficiencies. This would result in lower capital costs for all ratepayers." (page 22)

c. "The Staff proposes that future smart grid investments from utilities must correlate with the following objectives aimed at delivering transparent and identifiable benefits to ratepayers: (1) accommodate advanced generation and storage options, (2) enable informed participation by all customers, (3) support new products, services, and markets, (4) optimize existing assets, increase efficiency and improve reliability, and (5) operate resiliently against physical and cyber-attacks." (page 23)

d. "The Staff sees prudent utility investments in AMI as a first step toward realizing a modern grid. The Staff will continuously evaluate requests from utilities for recovery of advanced digital technology for consistency with prudency principles." (page 23)

Q. What did the Commission finally order in MPSC Case No. U-17000?

A. On September 11, 2012, the Commission (1) accepted Staff's Report on AMI and Smart Grid and (2) ordered, if and when, UPPCO and/or other utilities decide to implement AMI, that the companies shall provide an opt-out option or an explanation for why an opt-out provision is unnecessary or cost-prohibitive.

Q. Explain the relevance of MPSC Case No. U-18455 regarding UPPCO's application for the extension of the waivers granted in connection with the monthly meter reading requirements.

A. UPPCO currently does not have an AMI solution that allows the utility to read meters on a monthly basis. On October 25, 2017 ("October 25th Order") the Commission approved an application filed on September 21, 2017, by UPPCO for an extension of the waivers of the monthly meter reading requirements under Michigan Admin Code, R 460.113(1) (Rule 13(1)) and R 460.1608(1) (Rule 8(1)) of the Commission's billing rules applicable to residential and non-residential electric and gas customers, respectively.

In accordance with Michigan Admin Code, R 460.169(3) (Rule 69(3)) and R 460.1640(3) (Rule 40(3)), UPPCO had requested and been approved for waivers of the monthly meter reading requirements since the new rules were adopted; the most recent being the one-year waiver approved by the October 25th Order in this docket. Pursuant to the directives of the October 25th Order, on January 23, 2018, the MPSC Staff submitted a Report outlining its findings and recommendations. On May 4, 2018, UPPCO filed its response to the Staff's report. In its response, UPPCO reported that it added additional manual reviews for new service customers, decreased its tolerance limits for estimated bills, and implemented various system checks. Further, UPPCO stated that it was actively evaluating the deployment of AMI throughout its service territory and believed that the need for bimonthly estimates would be eliminated after completing AMI meter installations, resulting in increased accuracy of monthly power bills.

On June 28, 2018, Commission issued an Order ("June 28th Order") directing that, should the Company present an AMI solution that would resolve current estimated billing concerns, UPPCO shall do so in a Company-filed rate case with a benefit-cost analysis and business plan. Further, on page 5 of the June 28th Order, the Commission states the following:

> "Although the Commission is encouraged that UPPCO has cooperated with the Staff and made some progress toward necessary improvements to its estimated billing practices, such improvements do not give rise to the entitlement of unlimited future waivers or constitute an acceptable permanent solution to the absence of accurate monthly meter reading as required by Rule 13(1). Nor should the application for and granting of waiver requests be considered as merely routine. Providing accurate bills is a fundamental responsibility for any utility, and UPPCO's size or service location are not adequate justification for continued waivers."

> "…UPPCO's waiver applications have consistently chronicled that the company has been actively considering AMR/AMI technology and implied that progress was being made toward its installation."

Q. Provided the orders issued and the direction delivered in both MPSC Case Nos. U-17000 and U-18455, why is UPPCO investing in AMI and how will it benefit customers?

A. UPPCO has been evaluating AMI for several years, as evidenced in UPPCO's various meter reading waiver filings. Since late 2014, UPPCO has been focused on implementing and stabilizing numerous new, stand-alone operational and information technology ("IT") systems as part of its spin-off from its former parent company, and its creation as an independent Michigan-based utility.

With the Company's many systems now stabilized, and in response to many of our customers expressing concerns over UPPCO's reliance on estimated meter readings, as well as the Commission's language in the June 28th Order, UPPCO has begun implementation of an AMI solution that will benefit customers through (1) eliminating the need for bimonthly estimated meter readings, (2) helping modernize the power grid which will improve system reliability by providing the means for determining when and where unplanned outages occur, allowing for quicker restoration times, and (3) lower rates over the longer term through corresponding operational cost savings. Throughout 2018, UPPCO has been in constant contact with Commission Staff and other stakeholders regarding the evaluation and development of its potential AMI solution and business case.

Also, as evidenced in the attached publication from the United States Energy Information Administration ("EIA") on smart meter deployment across the nation, between 81% to 100% of residential customers in Michigan have smart meters. Please evidence Exhibit A-44, EIA Smart Meter Report.

PURPOSE OF TESTIMONY

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

A. The purpose of my direct testimony is to describe UPPCO's AMI project and business case. The Company is requesting: (1) approval and recognition in customers rates of $15,636,460 in projected capital expenditures associated with the installation of the Company's AMI investment, and (2) approval of the necessary tariffs and/or terms and conditions.

Q. How is your testimony organized regarding its AMI business case?

A. My AMI testimony is organized as follows:

1. UPPCO's AMI solution
2. Customer and Stakeholder engagement
3. Evaluation Process
4. AMI Preferred Partners
5. AMI Technology Alternatives
6. AMI Cost Analysis
7. AMI Benefit Analysis
8. AMI Financial Analysis
9. Revenue Requirement Analysis
10. Final Recommendation and Decision
11. Project Implementation Plan
12. Key Considerations for Accounting Treatment
13. Key Consideration for Regulatory

14. Conclusion

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. The exhibits are listed below.

1. Exhibit A-43, MPSC Staff Report U-17000
2. Exhibit A-44, EIA Smart Meter Report
3. Exhibit A-45, Itron OpenWay Riva Security
4. Exhibit A-46, Non-Standard Meter Provision Cost Calculation
5. Exhibit A-47, AMI Business Process Requirements Summary
6. Exhibit A-48, AMI Project Cost Analysis
7. Exhibit A-49, AMI Project Benefits OWOC
8. Exhibit A-50, AMI Project Benefits MDM
9. Exhibit A-51, AMI Financial Analysis
10. Exhibit A-52, AMI Revenue Requirement
11. Exhibit A-53, AMI Project Schedule
12. Exhibit A-54, Non-Standard Meter Definition
13. Exhibit A-55, Non-Standard Meter Provision

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

A. Yes.

UPPCO'S AMI SOLUTION

Q. Please describe UPPCO's AMI solution.

A. UPPCO's AMI solution will be implemented in multiple phases over the coming years. With each phase, UPPCO will focus on performance and system stabilization through proper testing and customer engagement. The first phase of UPPCO's AMI investment is focused on implementing foundational smart meter technology upon a platform that will be flexible to accommodate future technological advancements that may further enhance customer benefit and experience down the road . UPPCO's AMI solution focuses on this initial foundational stage of AMI which seeks to (1) provide AMI meters (i.e., "smart meters") capable of transmitting and receiving data through the replacement of UPPCO's existing analog/digital meters for all residential and small commercial customers; (2) through use of a Radio Frequency ("RF") mesh communications network, allow meters and other devices to route data through secure wireless networking technologies; (3) provide system integration to support the use of data for billing and key operational uses, such as improved outage management, and (4) deliver a customer interface / web portal.

Many of the direct operational benefits will be related to meter reading automation, operational efficiencies in field and meter services, reduction in unaccounted for energy, operational efficiencies in billing and customer care, and improved outage management efficiency. Customers can also expect to realize improved/enhanced customers service, billing accuracy, and reliability, and will be provided with the capability and tools to make more informed decisions on energy usage.

By taking advantage of advancements in metering technology and leveraging two-way RF networks, UPPCO will strive to ensure high-quality service in a cost-effective manner through this AMI initiative. Given that this AMI system will be of benefit to customers over an extended period of time, UPPCO has conducted its financial analysis over a 20-year time horizon, during which time the Company can evidence that benefits exceed costs, with a reasonable payback period for its investment.

Q. How does UPPCO plan to leverage AMI for modernization of the power grid?

A. In addition to the functionality of accurate monthly reads, automation of business processes, tamper and theft detection, an improved customer portal, and a more efficient Outage Management System ("OMS"), UPPCO is also building the foundation to add future AMI functionality. Potential future functionality being considering for later phases are interval and time-of-use (TOU) billing options, as well as overall system monitoring for better future planning and load settlement. Extending the coverage of our AMI program to include larger commercial customers is something UPPCO is also evaluating.

Q. How many existing meters is UPPCO looking to replace as part of its AMI project?

A. UPPCO is planning to replace 58,819 existing meters.

Q. What is the approximate timeline of the planned AMI implementation?

A. UPPCO plans to engage with its chosen vendors for educational workshops and project planning, as well as begin stakeholder engagement, in Q3-2018. Once complete, UPPCO and its vendors will begin to build the hosted environments that house the software, the head-end (the user interfaces and dashboards to run the AMI system) and the back-end (the IT systems to store and process data) beginning in Q4-2018. When most of the head-end and back-end are up and running, UPPCO will begin a measured installation of the Field Area Network ("FAN") which consists of extenders, collectors, and smart meters within its larger network to start functional testing of the communication devices and meters. UPPCO estimates this starting in Q4-2018 and extending into Q1-2019. Once preliminary tests from a measured network rollout are successful, UPPCO will then complete the build out of their entire FAN and prepare for mass deployment of meters. UPPCO estimates this beginning approximately in Q2-2019, along with the commencement of the mass deployment. Mass deployment is estimated to take roughly six-months, ending in Q4-2019.

CUSTOMER & STAKEHOLDER ENGAGEMENT

Q. How does UPPCO plan to engage customers in the AMI roll-out?

A. UPPCO plans to use a variety of communication channels, such as website resources, billing inserts, media and door hangers to engage each set of stakeholders and to promote proactive engagement in the development of the specific program elements the AMI deployment will support.

Q. Will the Company meet with community leaders and stakeholders as the AMI rollout nears?

A. Yes. In addition to direct customer outreach, the Company plans to meet with communities across its service territory in order to describe the overall installation process, and, in general, keep the communities well-informed. The ready transfer of information to customers and the community will be further enhanced by Company's website and billing inserts which will contain specific and pertinent information regarding UPPCO's AMI implementation. In general, the website and billing inserts will consist of an overview of the AMI meter program and contain a frequently asked questions (FAQs) section as well as other sections addressing safety and privacy.

Q. Please summarize the Company's plan regarding cyber-security and privacy within the context of its AMI implementation.

A. One of the key interests UPPCO has in a hosted solution is leveraging a cloud environment that it's chosen infrastructure vendor, Itron, Inc. ("Itron"), has used on numerous other AMI Projects. The hosted solution has built-in security measures to prevent cyber-attacks and to protect customer data from falling in the wrong hands. Itron's hosted environment implements multiple layers of protection which are strategically located throughout the system architecture to provide the industry's most comprehensive, unified security available today. We've also included language in our contracts with all of our vendors to ensure that they adhere to specific customer data protection as well as submit their plans for how they'll keep customer data protected. As evidence, please find Exhibit A-45, Itron OpenWay Riva Security that more fully describes Itron's security measures.

Q. Will customers have an opportunity to "opt-out" of receiving the many benefits of installing an AMI meter?

A. Yes. UPPCO will provide instructions for opting out of the Company's standard AMI meter installation prior to each scheduled installation through the election of the Company's Non-Standard Meter Provision. UPPCO will have multiple venues in place to provide customers with information regarding smart meters and the opt-out process. The Company will also have resources assigned to respond to potential non-adopters to address any concerns or questions they may have relating to AMI safety, privacy and security.

Q. Will UPPCO's Non-Standard Meter Provision provide reasonably accurate price signals to customers who elect not to have an AMI meter installed?

A. Yes. This incremental charge will be based on UPPCO's cost of service to manually read any Non-Standard Meter. This price signal, while subject to change pursuant to the outcome of this general rate case, will provide customers with a price indication that will allow customers to make an informed decision. As evidenced on line 29 of Exhibit A-46, Non-Standard Meter Provision Cost Calculation, UPPCO estimates the per customer monthly charge to be $14.26 per month, along with a $62.25 one-time cost, as seen on line 47, to exchange and test meter for opt-out after the AMI project is fully implemented. These calculations and the resulting rates and charges are a direct function of the number of opt-out customers electing this provision. On a cost-of-service basis, these charges may fluctuate depending on the outcome of this general rate proceeding and the number of participants electing to opt-out.

Q. In this cost of service analysis, how many customers has UPPCO assumed to elect the Non-Standard Meter Provision?

A. In the supporting analysis of Exhibit A-46, UPPCO has conservatively assumed 500 customers, which is less than 1%, but more than the approximate 0.5% that other utilities have experienced in Michigan.

Q. How will UPPCO follow up with customers once an AMI meter has been installed on their premises?

A. Immediately following installation, a door hanger will be left behind indicating that an AMI meter was installed and will briefly summarize the many benefits that the new smart meter will make possible.

Q. Did UPPCO reach out to other utilities who have implemented AMI?

A. Throughout the process of determining UPPCO's final solution, UPPCO reached out to several other utilities. There were conference calls with DTE Electric Company ("DTE") and Consumers Energy ("Consumers") to gain lessons learned from analyzing and deployment processes and engagement processes. UPPCO also did a site visit at Consumers to tour their Smart Energy Operations Center as well as their meter technology department. During the site visit, Consumers' and UPPCO's core AMI teams exchanged valuable information, along with participating in a various question and answer sessions. Further, once UPPCO chose its preferred infrastructure vendor, Itron also set up conference calls with other utilities they've worked with, and who had selected similar solutions to UPPCO's, in order to help guide UPPCO through the process.

EVALUATION PROCESS

Q. Please describe the Company's evaluation process regarding its AMI solution and the vendor identification, evaluation and selection process.

A. UPPCO first identified its business needs and its required functionality to facilitate those needs. UPPCO then evaluated a range of possible technologies that could best satisfy its identified business needs. Through this process UPPCO determined that an AMI solution was functionally superior to an alternative automated meter reading ("AMR") solution due to the broader functionality, enhanced customer benefits, and future customer engagement and technological enhancement possibilities. Once AMI was selected as the preferred solution for its business needs, UPPCO then identified and assessed various possible partners and AMI technology options, as well as evaluated their suitability for interfacing and integrating with UPPCO's current technology and IT environments. Following the identification of possible and suitable AMI options, the Company then performed a comparative benefit-cost analysis on each AMI option to determine its final solution. Finally, UPPCO continued to engage with other utilities, as well as with Commission Staff in order to better understand and learn from their collective experiences.

Q. Please describe the customer value proposition.

A. One of the benefits of introducing an AMI solution is that UPPCO will eliminate its current use of estimated billing. By increasing the accuracy of its billing by tying actual consumption to billing each month, customers will no longer be exposed to estimations based on historical consumption levels, which may or may not reflect current usage. Reduced customer service inquiries are also expected with the elimination of bill estimation as customers will no longer be calling UPPCO's customer service center to clarify how their billing estimates were determined. Improved customer engagement through an enhanced customer portal is another feature that will help increase customer satisfaction. Installing AMI meters and integrating them into UPPCO's current OMS will help UPPCO identify customer outages quicker and decrease outage time due to isolating and more efficiently identifying the cause of outages. AMI will also aid in determining when power has been restored to each customer sooner than at present. Another aspect of AMI functionality will be an improved ability to identify meters that have been tampered with, thereby reducing the possibility of theft, which is beneficial to all UPPCO customers. Finally, the initial phase of UPPCO's AMI program builds the foundation for possible future enhancements and functionality that could continue to add supplemental benefit to UPPCO customers in later phases.

AMI PREFERRED PARTNERS

Q. Please identify the possible partners and vendors that were evaluated during UPPCO's evaluation process.

A. UPPCO initially identified seven possible vendors for evaluation. As the business needs and system integration requirements were further refined, UPPCO was able to reduce this list down to three preferred vendors: Itron, Eaton Corporation and Landis & Gyr Corporation. Each of these companies is a leader in AMI technology deployment and has an excellent track record in successfully implementing solutions similar to what UPPCO is requiring.

Q. Who did UPPCO chose as its key preferred partners for the AMI project and for incorporation into the detailed benefit-cost analysis?

A. UPPCO selected both Itron and Utegration, Inc. ("Utegration") as its key vendors for its AMI implementation. Upon review, both Itron and Utegration clearly separated themselves as the preferred partners for UPPCO in the following four key areas:

1. Itron is an industry leader in energy resource management and metering, and has a significant presence within the State of Michigan, with more than 1/3 of electrical customers served with their AMI meters;
2. Itron has currently partnered with other utility industry leaders within the State of Michigan, such as Consumers Energy, DTE Energy, and Alpena Power Company. Each of these companies, when contacted by UPPCO, recommended the use of Itron based on their experiences with the vendor;
3. Itron's price was competitive and their proposed solution met UPPCO's business process requirements, as evidenced in Exhibit A-47 ; and
4. Itron's proposed solutions have previously worked well with other vendors that UPPCO will be engaged with during this project implementation. Utegration, for example, which is a current vendor assisting UPPCO with its new IT system finalization and stabilization, and which has excellent familiarity with UPPCO's core business processes, has worked with Itron on the integration of its AMI system with other utilities. Both of these vendors have also worked together with other utilities who are also using the same SAP Customer Information System (CIS) that UPPCO is currently using.

Q. Please describe the process by which UPPCO engaged both Itron and Utegration with regard to defining the business and functional requirement for this AMI project.

A. After UPPCO completed its RFP process with its shortlist of vendors, the Company engaged Itron and Utegration in Q1-2018 for preliminary workshops to familiarize all parties with UPPCO's current business processes, as well as the business requirements selected for the implementation of the Company's AMI project. These workshops also helped UPPCO understand possible technology options available to meet its needs and gain an understanding as to how the various implementations might proceed. Following this step, the vendors provided cost proposals for each option evaluated. Once these proposals were received, UPPCO then had several follow-up meetings in Q2-2018 to further refine and evaluate the options.

AMI TECHNOLOGY ALTERNATIVES

Q. Please list and define the various AMI technology alternatives that were evaluated with Itron and Utegration.

A. With an Itron Openway Riva RF Mesh solution, the following technology options were evaluated:

1. On-Premise | OWOC: installation of smart meters utilizing a simple head-end software system. This option does not include a Meter Data Management ("MDM") system. The software in the On-Premise options would reside on servers that UPPCO would own, install and control on UPPCO property;
2. On-Premise | MDM – 3 Tier: this option would utilize the same smart meters but includes additional servers and software and includes an MDM system which would reside in UPPCO's back-end. This would allow the system to better utilize the data that the smart meter would collect and would provide additional billing and meter processes, data validation and operational efficiencies. The MDM is also the center piece of the foundation that would enable future enhancements;
3. On-Premise | 2 Tier: this option would utilize the same smart meters but would include additional servers and software and include an MDM system which would

reside in the CIS that SAP provides. This allows the system to better utilize the data the smart meter collects and would provide additional billing and meter processes, data validation and operational efficiencies. The MDM is also the center piece of the foundation that would enable future enhancements;

4. Hosted | OWOC: installation of smart meters utilizing a simple head-end software system. This option does not include an MDM system. The software in the Hosted options would reside on servers that Itron would supply in their hosted environment, with Itron maintaining ownership and operation; and

5. Hosted | MDM – 3 Tier (chosen option): this option would utilize the same smart meters but includes additional servers and software and includes an MDM system. This option allows the system to better utilize the data the smart meter collects, and provides additional billing and meter processes, data validation and operational efficiencies. The software in the Hosted options would reside on servers that Itron would supply in their hosted environment, with Itron maintaining ownership and operation. The MDM is also the center piece of the foundation that would enable future enhancements.

Q. Are each of the above listed technology options evaluated in UPPCO's AMI cost analysis?

A. Yes, the cost analysis is explained below.

AMI COST ANALYSIS

Q. Please explain the approach taken by UPPCO for its cost estimation.

A. The UPPCO AMI project team worked through a Request for Proposal ("RFP") process to engage with its short-list of technology vendors to obtain cost estimates for AMI field hardware (meters and communications infrastructure), installation, software purchase, and administration costs. This RFP process was completed prior to the preliminary scoping workshops with Itron and Utegration. The team also engaged with external IT vendors, internal IT personnel and key internal planning groups to assess the costs associated with hardware procurement, software purchasing and licensing, IT development and integration, and overall support and maintenance of the IT systems and infrastructure needed during AMI deployment. Internal business groups and stakeholders also assisted in identifying resource requirements and generating cost estimates for program management and associated operational activities such as customer education, customer management, and technical support.

Q. Identify the exhibit that supports UPPCO's cost analysis?

A. Please find Exhibit A-48, AMI Project Cost Analysis.

Q. Please describe the cost categories that were evaluated among all of the alternatives, and where necessary give further description of the technology requirements and integration needs within each category.

A. For each of the technology alternatives, UPPCO evaluated the following cost categories, listed below:

1. **Project Preparation and Integration Costs**: This cost category includes UPPCO's internal costs associated with the implementation and detailed design workshops, stakeholder communications, and current project work order costs.

This category also includes ITRON's implementation costs, project expenses, and utility customization services. Utegration's associated work with the CIS(SAP)/MDM interface and associated project expenses are also included in this category. These collective costs for each of the alternatives evaluated can be seen in Exhibit A-48 and are summed on both a capital and expense basis on line 12.

2. **IT Systems (UPPCO back-end and Itron head-end)**: This cost category includes all of the implementation costs associated with the IT systems, including integration hardware, software, development, security and project management, as well as the ongoing maintenance of these systems. Costs in this category are further broken down into those from UPPCO's back-end system plus those of Itron's head-end system as previously described.

The AMI IT systems include head-end systems to communicate with the AMI network, capture meter data, and send control commands to the meter. Itron's head-end systems transfer data to a MDM where meter data is validated against acceptance rules to ensure data quality. Estimations are done for missing data and edits are made to some data elements. Storage systems are needed, as meter data increases exponentially over current needs, increasing the importance of systematic data management. Data will need to be shared by the systems, and it requires an integration platform to allow sharing of the information between various systems (e.g. providing data for various applications such as billing, customer service and customer analytics). Security of the AMI network, including planning and implementation of security architecture to protect customer and operational data, is required. As evidenced in Exhibit A-48, the individual component costs are listed on lines 14 and 15 for UPPCO back-end costs and the individual component costs are listed on lines 17 through 27 for Itron head-end costs. These costs are identified for each of the technology alternatives evaluated and are ultimately summed on both a capital and O&M basis on line 28.

3. **Field Area Network**: The AMI communications network hardware and installation involves the physical roll-out of the communications hardware (collection points, repeaters) in the field. The FAN fills the communication gap between the core networks and the smart meters. The FAN is most often implemented with wireless networking technologies because of their large geographic coverage areas and large number of connected devices, making it technically and economically infeasible to implement them using wired technologies. Wireless networking technologies used in FANs include cellular, narrowband point-to-multipoint ("PTMP"), broadband PTMP and broadband wireless RF Mesh networks. As evidenced in Exhibit A-48, the individual component costs are listed on lines 30 through 35 for the FAN. These costs are identified for each of the technology alternatives evaluated and are ultimately summed on both a capital and O&M basis on line 36.

4. **AMI Meters**: The AMI meter costs include the costs for the physical AMI meter for single-phase meters having embedded two-way RF communicators. All self-contained meters that are 200 Amps or less will also have an internal switch for remote connect / disconnect applications. During pre-installation, facilities are prepared for AMI meter processing, and plans are developed for meter

deployment. Network preparation, including right of ways and inter-agency permissions are obtained if needed. During field deployment, the meters are installed at the customer premises (and the existing meter is taken out of service). Meter deployment is a major activity which involves coordinating with a Meter Install Vendor (MIV) on many processes. UPPCO and the MIV first need to plan a deployment schedule that uses UPPCO's current meter reading routes to maintain manual billing of customers until the MIV is able to get to the residence in their deployment schedule. Standard operating procedures also need to be agreed upon in order to maintain UPPCO's current processes. These include installation of meters, quality control, inventory of new and old removed meters, communication with customers, safety and appearance. Finally, a process for handling opt-out and Returned to Utility installation orders needs to be developed to handle these special situations. The meters are tested for performance and accuracy before deployment, and the testing of meter communication and data accuracy will be performed as a part of the commissioning. These collective meter related costs for each of the alternatives evaluated can be seen in Exhibit A-48 and are summed on both a capital and expense basis on line 42.

5. **Contingency**: UPPCO's contingency is 5% of the capital expenditure total for each of the alternative evaluated and can be seen in Exhibit A-48 on line 44.

Q. Please summarize the total capital costs expected to be incurred during the multi-year implementation of the AMI systems, and the anticipated annual system operating and maintenance ("O&M") costs for each of the three on-premise (OWOC, MDM-3 Tier and 2 Tier) solutions.

A. As seen in Exhibit A-48, the following costs are shown on line 46 for the three on-premise solutions:

1. OWOC (on-premise):
   a. Capital: $17,023,727
   b. O&M: $1,011,325 in Year 1 of operation
2. MDM-3 Tier (on-premise):
   a. Capital: $19,714,176
   b. O&M: $953,030 in Year 1 of operation
3. 2 Tier (on-premise):
   a. Capital: $18,376,070
   b. O&M: $1,014,045 in Year 1 of operation

Q. Please summarize the total costs for the two Itron-hosted (OWOC and MDM-3) solutions.

A. As evidenced on line 46 in Exhibit A-48, the following costs are evident.

1. OWOC (Itron-hosted):
   a. Capital: $13,258,515
   b. O&M: $730,550 in Year 1 of operation
2. MDM-3 Tier (Itron-hosted):
   c. Capital: $15,636,460
   d. O&M: $580,550 in Year 1 of operation

Q. What observations can be made regarding the cost analysis?

A. As evidenced above and in Exhibit A-48, the on-premise technology solutions have not only higher capital costs, but also higher O&M costs when compared to Itron-hosted solutions.

AMI BENEFIT ANALYSIS

Q. Please explain the benefit estimate approach undertaken by UPPCO.

A. UPPCO evaluated the benefits/savings on both the OWOC and MDM solutions. The UPPCO AMI project team relied heavily on both internal and external AMI and metering experts to identify AMI benefit areas, and to detail the cost reductions and loss preventions associated with each of the benefit area in line with the proposed meter deployment schedule. Several direct operational and customer benefits in several areas such as meter reading, field and meter services, unaccounted for energy, billing accuracy, and consumption on inactive meters have been included in the analysis and business case.

Q. Please identify the exhibits which support UPPCO's benefit analysis.

A. Both Exhibit A-49, AMI Project Benefits for OWOC and Exhibit A-50, AMI Project Benefits for MDM, provide a summary of UPPCO's projected AMI program benefits. In column (B), annual benefits for year 1 and 2 are identified. These benefits are steady-state benefits that will grow over time as the systems and processes stabilize and mature. In column (C), annual benefits for years 3 and beyond are identified. These benefits are projected to be greater as they are primarily driven by UPPCO realizing greater efficiencies in OMS and meter services as systems and processes stabilize and mature.

Q. Please describe the benefit categories that were evaluated consistently among all of the five alternatives and provide a brief narrative on the categories with the largest savings.

A. For all five of the OWOC and MDM solutions, UPPCO evaluated the following benefit categories as summarized below, and as evidenced in Exhibit A-49 and Exhibit A-50.

1. **Meter Reading Cost**: These benefits include cost savings arising from reduced manual (bi-monthly) meter reading staffing, along with reductions in associated costs, such as the need for fewer vehicles, lower fuel costs, vehicle insurance, and vehicle maintenance, as well as the avoided cost of monthly manual meter reads. Meter reading annual cost savings are evidenced in detail in Exhibit A-50 on lines 2 through 4 for the MDM solution. As evidenced in this same exhibit on line 1, total savings from Meter Reading Costs in years 1 & 2 is $1,669,132, while in years 3 and beyond, costs savings remain $1,669,132. Meter reading annual cost savings are evidenced in detail in Exhibit A-49 on lines 2 through 4 for the OWOC solution. As evidenced in this same exhibit on line 1, total savings from Meter Reading Costs in years 1 & 2 is $1,547,610, while in years 3 and beyond, costs savings remain $1,547,610.

2. **Meter Services**: AMI's smart metering and communication infrastructure enables utilities to perform several functions remotely that would otherwise require a field visit to the customer's premise. As a result, significant cost savings through the reduction in the number of personnel and vehicles for field and meter services will also be achieved. Meter Services annual cost savings are evidenced in detail in Exhibit A-50 on lines 6 through 8 for the MDM solution. As

evidenced in this same exhibit on line 5, total savings from Meter Services in years 1 & 2 is $11,610, while in years 3 and beyond, costs savings remain $410,121. Meter services annual cost savings are evidenced in detail in Exhibit A-49 on lines 6 through 8 for the OWOC solution. As evidenced in this same exhibit on line 5, total savings from Meter Services in years 1 & 2 is $11,610, while in years 3 and beyond, costs savings remain $144,447. Benefits in this area will be seen in the reduction in manual disconnect / reconnect of meters, single light outages, need for manual re-reads, as well as customer equipment problem outages, as further detailed below.

a. Reduction in manual disconnect / reconnect of meters (line 6 of both exhibits). The remote connect / disconnect feature of AMI smart meters enables utilities to turn on and off services for new and cancelled accounts remotely without a field trip. This benefit not only applies to the ability to turn on and off services for regular move-in / move-out of customers, but also provides the ability to cancel service for non-paying customers. As a result, significant cost savings can be realized through the reduction in need for personnel and associated transportation costs (fewer vehicles, reduced operating, maintenance and insurance costs) to turn on / off services. Additional cost savings will also be had through the time saved in relation to premises with meter access challenges.

b. Reduction in manual off-cycle / special meter reads (line 7 of both exhibits). UPPCO currently incurs costs to conduct manual off-cycle special meter reads. These reads are conducted for tenant changes, re-

reads, high bill inquiries, and other instances when a reading is needed off of the normal read cycle, and the elimination of these off-cycle and special reads will also result in similar labor and transportation related savings.

c. Reduction in power quality, and customer equipment problem field trips (line 8 of both exhibits). AMI implementation is expected to result in cost savings associated with fewer field trips to customer premises to investigate reduced power quality and equipment problems. With the ability to provide near real-time power and outage status information, AMI systems are able to test for loss of voltage at the service point as well as detect outage conditions and obtain indications of the restoration status. As a result, most power quality field trips will be eliminated for smart meter premises, leading to further labor and transportation savings.

3. **Increase OMS Efficiency**: AMI will enable UPPCO to obtain automated and immediate outage notification from the smart meters, which will allow the Company to know the exact location of outages, as well as to verify when power has been restored. These features will allow crews to be deployed more efficiently to outage areas, further improving crew management efficiency and assisting the company in lowering its average duration of outages. Additional truck rolls will also be eliminated by remotely verifying that all customers in an area have been restored before dispatching a crew to its next location. OMS annual cost savings are evidenced in detail in Exhibit A-50 on line 10 for the MDM solution. As evidenced in this same exhibit on line 9, total savings from OMS in years 1 & 2 is $113,189, while in years 3 and beyond, costs savings

increase to $269,291. OMS annual cost savings are evidenced in detail in Exhibit A-49 on line 10 for the OWOC solution. As evidenced in this same exhibit on line 5, total savings from OMS in years 1 & 2 is $113,189, while in years 3 and beyond, costs savings increase to $269,291.

4. **Customer Care**: Another significant benefit of AMI will be the cost savings and improved customer service experience realized through reduced call volumes and improved customer service management. Meter reading errors are expected to be virtually eliminated with the introduction of the smart meters, as will the need to calculate and respond to inquiries in relation to bi-monthly reading and interim billing estimation. Efforts to raise awareness of the AMI program and its benefits through marketing campaigns and enhanced customer education, is also expected to drive more customer traffic to the web portal, which in turn is expected to lead to further adoption of the expansive list of self-service functionalities, and lead to a further reduction in call volumes and call center staffing. Customer Care annual cost savings are evidenced in detail in Exhibit A-50 on lines 12 through 14 for the MDM solution. As evidenced in this same exhibit on line 11, total savings from Customer Care in years 1 & 2 is $452,915, while in years 3 and beyond, costs savings increase to $541,315. Customer Care annual cost savings are evidenced in detail in Exhibit A-49 on lines 12 through 14 for the OWOC solution. As evidenced in this same exhibit on line 11, total savings from Customer Care in years 1 & 2 is $452,915, while in years 3 and beyond, costs savings remain $452,915. These costs savings are further described below:

a. Reduction in uncollectible expense / bad debt (line 12 of both exhibits). Given that AMI meters will be able to perform remote disconnects and re-connects, UPPCO expects improvement in efficiency from its currently manual process to schedule the timing and organize its field crews for disconnects. UPPCO estimates that AMI will help it recover uncollectible expenses through both a faster processing of g remote disconnects for non-pay disconnect orders in alignment with the existing regulatory timelines, and by eliminating the backlog of disconnections due to the timing of field crew availabilities.

b. Reduction in customer call volume (line 13 of both exhibits). Through the AMI program roll-out, customers will be further educated about the wide variety of self-service options available to them on the UPPCO web portal, allowing for further reduction in call center staffing;

c. Reduction in customer accounts back-office costs (line 13 of both exhibits). Detailed information regarding the status of each AMI meter will allow UPPCO to detect stopped or faulty meters on a real-time basis, whereas meters that have stopped or are not registering an accurate reading as a result of device failure currently require a manual intervention to investigate the issue. Through the implementation of AMI, UPPCO therefore expects to be able to reduce the back-office effort required to intervene on a stopped meter incident; and

d. Reduction in estimated bills (line 14 of both exhibits). The ability to remotely read meters on a frequent basis not only will eliminate estimation for current bi-monthly read customers but will also reduce the number of estimated bills that often result from meter access issues that currently prevent meter readers from obtaining reads in hard to access areas at the customer premise. Fewer customer service resources are therefore expected to be needed to review exception reports, resolve billing errors and process adjustments;

5. **Reduction in Unaccounted for Energy**. Unaccounted for Energy ("UFE") in the areas of meter tampering, energy theft, meter inaccuracy, and dead / stopped meters results in significant revenue loss for utilities. Through the use of smart meters and sophisticated MDM systems, UFE can be detected early and revenue losses related to unmetered energy can be reduced. UFE annual cost savings are evidenced in detail in Exhibit A-50 on line 16 for the MDM solution. As evidenced in this same exhibit on line 15, total savings from UFE in years 1 & 2 is $115,000, while in years 3 and beyond, costs savings remain $115,000. To come to this number UPPCO reviewed Ameren Illinois' AMI Cost/Benefit Analysis. Which states, 'In reviewing various public utility AMI filings, Ameren Illinois observed that other utilities estimated savings in the range of 0.5% - 1% of revenue associated with each AMI meter.' UPPCO used a conservative 0.25%.

Q. Please summarize key observations based upon the benefits (savings) analysis.

A. Listed below is a list of key observations:

1. The total benefits associated with an MDM solution are greater than the benefits of an OWOC solution, as evidenced on line 15 of Exhibit A-49 and Exhibit A-50 .
2. The annual benefits associated with Meter Reading Costs constitute over 50% of the savings and is larger for an MDM solution when compared to the OWOC solution, as evidenced on line 1 of Exhibit A-49 and Exhibit A-50.
3. The annual benefits associated with Customer Care are greater in an MDM solution in Year 3 and beyond when compared to an OWOC solution, as evidenced on line 11 of Exhibit A-49 and Exhibit A-50.
4. As evidenced on line 15 of Exhibit A-50, an MDM solution provides the additional benefit UFE savings. This benefit does not exist in the OWOC solution.

AMI FINANCIAL ANALYSIS

Q. Please describe the financial analysis undertaken by UPPCO in evaluating the possible AMI technologies for implementing Itron's Openway Riva RF Mesh solution.

A. UPPCO's approach to the cost-benefit analysis was a two-step process which included the use of a simple payback and Net Present Value ("NPV") analysis as the first step to evaluate the different AMI technology scenarios, and to identify the highest value solution. Once the preferred solution was identified, UPPCO then developed an associated revenue requirement calculation on this solution to further evidence the costs and benefits of the AMI project from a customer perspective.

All costs and benefits used in this analysis for each different investment scenario are incremental to UPPCO's existing baseline operations. In compliance with Michigan Admin Code, R 460.113(1), the baseline scenario reflects the related costs and benefits that would be anticipated if the investment were not made and the waiver of this filing requirement was not granted by the Commission. The time horizon used for the business case was 20 years.

Q. Please identify the exhibit which supports UPPCO's payback analysis and describe the findings.

A. UPPCO's payback analysis involves calculating when the cumulative customer benefits equal and begin to exceed the cumulative customer costs. This is useful in understanding to what extent the realization of the project benefits cumulatively lags the incurrence of the project costs. As can be seen in Exhibit A-51, AMI Financial Analysis, the payback period for the five evaluated AMI scenarios range from 8 to 14 years as seen on line 2, with the fastest payback being for the Hosted MDM-3 Tier technology.

Q. Please identify the exhibit that supports UPPCO's NPV analysis and describe the findings.

A. In UPPCO's NPV Analysis, as also demonstrated in Exhibit A-51, the annual costs and benefits of cash flows for each of the five evaluated AMI technology scenarios are discounted by a discount rate equivalent to UPPCO's weighted average cost of capital (WACC) approved in MPSC Case No. U-17895. As seen in this exhibit on line 16, the NPVs range from ($498,350) to $8,671,849, with the latter being for the Hosted MDM 3-Tier technology. In this analysis, any NPV of greater than zero signifies an investment that earns a positive financial return after accounting for the time-value of money over the considered 20-year investment time horizon.

REVENUE REQUIREMENT ANALYSIS

Q. Please identify the exhibit that supports the revenue requirement analysis performed by UPPCO on its preferred Hosted MDM 3-Tier technology alternative and explain how the analysis was performed.

A. UPPCO's revenue requirement impact analysis is seen in Exhibit A-52, AMI Revenue Requirement. In this analysis, the avoided cost of manual monthly meter reads from the AMI benefits valued at $940,000 were removed, as customers already receive this benefit today and as such it is reflected in present rates. A list of other key assumptions used in the revenue requirement analysis are as follows:

1. UPPCO's total combined capital spend for 2018 and 2019 is $15,636,460;
2. UPPCO has separated the project into 3 primary components with the following projected capital expenditures for 2018 and 2019:
    a. Meters: $10,609,732 with a book depreciable life of 30 years and a tax life of 20 years.
        i. 2018: $6,172,994
        ii. 2019: $4,436,738
    b. IT Network: $2,708,747 with a book depreciable life of 5 years and a tax life of 1 year.
        i. 2018: $1,594,401
        ii. 2019: $1,114,346

c. Field Area Network: $2,327,981 with a book depreciable life of 12 years and a tax life of 5 years.

i. 2018: $935,595

ii. 2019: $1,382,386

3. UPPCO used a Federal income tax rate of 21%;
4. UPPCO used a State income tax rate of 6%;
5. UPPCO assumed a 2.5% Property Tax rate for assets in the field;
6. UPPCO escalated O&M benefits and costs by 2.8% to account for inflation;
7. UPPCO utilized components of its 2019 projected capital structure as identified on Exhibit A-14 to apply the debt interest before tax and the equity return after tax;
8. Book depreciation is calculated based on the projected in-service quarter and tax depreciation is based on modified accelerated cost recovery system (MACRS) half-year convention, unless the project is installed in Q4; and

9. The present value year is 2018.

Q. Please explain the results of the revenue requirement analysis.

A. As seen in Exhibit A-52, from a customer perspective, annual benefits (savings) begin in 2020 and become greater than annual costs in 2025. As evidenced in this exhibit, because project implementation is scheduled to be completed by some time in Q4-2019, not all the capital expenditures expended by UPPCO in 2019 will be reflected in its 13-month average rate base, nor will the savings begin accruing until early 2020.

FINAL RECOMMENDATION AND DECISION

Q. What is UPPCO's final recommendation and decision regarding its AMI solution? Please explain.

A. Based on the testimony and considerations outlined above, UPPCO has selected a Hosted MDM 3-Tier technology along with Itron's Openway Riva RF Mesh solution. With all AMI alternatives evaluated on a comparable basis, the Hosted MDM 3-Tier technology alternative is preferred because it (1) meets UPPCO's business and functional requirements, (2) has the best financial payback and return of the alternatives evaluated, (3) positions UPPCO customer on technology platform that can be leverage for future growth and customer benefits, and (4) will be implemented by market leaders, Itron and Utegration, which have a proven track record of successful implementations in the industry.

PROJECT IMPLEMENTATION PLAN

Q. At a high-level, please describe UPPCO's implementation plan.

A. Yes. Please find attached Exhibit A-53, regarding UPPCO's AMI Project Schedule.

1. Project Development: targeted completion by end of Q3-2018
2. Installation of Back Office Equipment: targeted completion by Q1-2019
3. Installation of Network Equipment:
    a. Field Installation to begin by Q4-2018
    b. Targeted completion by Q2-2019
4. Installation of Customer Meters:
    a. Meter Installation to begin by Q2-2019

b. Targeted completion by late Q3/Q4-2019

5. Project Completion:

a. Targeted completion by Q4-2019

KEY CONSIDERATIONS FOR ACCOUNTING TREATMENT

Q. Is UPPCO calculating AFUDC for this project? Please explain.

A. Yes. Please find Exhibit A-20 of Company Witness Kates. This exhibit informs Schedule C11 of Exhibit A-13 of Company Witness Kates, as well.

Q. Pursuant to Exhibit A-20, when is UPPCO recording its new AMI meters as plant-in-service?

A. January 2019, which is consistent with current business practice. UPPCO anticipates receiving and taking ownership of the new meters, and, at that time, the new AMI meters will be recognized as plant-in-service like all other meters.

Q. What depreciation rates are UPPCO using in its analysis?

A. UPPCO is utilizing its currently approved depreciation rates and methods authorized by the Commission in its December 16, 2009 Order Approving Settlement in consolidated Case Nos. U-15988 and 15989.

Q. What is the approximate value of UPPCO's current meters that will be retired when they are replaced with the new AMI meters?

A. The value of the current meters being replaced is approximately $4,500,000.

Q. From a timing perspective, when is UPPCO retiring its meters?

A. UPPCO will retire its existing meters coincident with its implementation schedule of new AMI meters in 2019, which is anticipated to occur primarily between June 2019 and November 2019.

Q. Is the anticipated retirement value of UPPCO's retired meters accounted for in UPPCO's 2019 projected rate base value in this general rate proceeding, as well as the capital expenditures associated with the new AMI meters?

A. Yes, the rate base value of $278,888,974 evidenced on line 21 of Schedule B1 of Exhibit A-12 of Company Witness Kates includes the assumed retirement value of the retired meters, as well as the replacement value of the new AMI meters on a 13-month basis.

KEY REGULATORY CONSIDERATIONS

Q. Has UPPCO developed an "opt-out" provision, whereby customers can opt-out of using UPPCO's Standard Meters?

A. Yes, please find Exhibit A-55, Non-Standard Meter Provision

Q. How does UPPCO define its "opt-out" election?

A. UPPCO's defines it as the Non-Standard Meter Provision, as evidenced in Exhibit A-54. Through its AMI program implementation, UPPCO has defined the following terms in its Standard Rules & Regulations regarding (1) Definitions, Technical Terms and Abbreviations, and (2) Terms and Conditions of Service:

1. Non-Standard Meter – any electromechanical, analog or digital meter that Company has either left in place per the Customer's election or otherwise deemed Non-Standard by the Company.

2. Standard Meter – all meters that are not deemed a Non-Standard Meter by the Company.

Q. What customers are eligible for the Non-Standard Meter Provision?

A. Customers served on Residential Service have the option to choose a Non-Standard meter. For a customer to be eligible to participate in the Non-Standard Meter Provision, the customer must have a meter that is accessible to Company employees and the customer shall have zero instances of unauthorized use, theft, fraud and/or threats of violence toward Company employees.

Q. For a customer electing the Non-Standard Meter Provision, what charges will the customer be subject to due to the Company needing to manually read the meter?

A. Again, as evidenced in Exhibit A-46, a customer electing the Non-Standard Meter Provision will have a Non-Standard Meter installed at their premises, have the meter read manually monthly, and be subject to the following charges:

1. Upfront Charge: $62.25, a one-time charge per billing meter per request
2. Monthly Charge: $14.26, per month charge at each premise as defined by the Company's Standard Rules and Regulations. Multiple metered units shall be charged per billing meter.
3. A Customer whose current meter is a Standard Meter and requests a Non-Standard Meter will pay the Upfront Charge at the time they request this option but will not pay the monthly charge until the Non-Standard Meter is installed.

Q. For a customer electing the Non-Standard Meter Provision, what happens to their existing meter?

A. UPPCO's plan is for the customer to keep their existing meter until it expires. The customer's current meter will be tested by UPPCO on its regular meter testing cycle. When the Non-Standard Meter does fail, the meter will be replaced by an existing Non-Standard Meter. To the extent the Company has any residual analog meters in stock, it will replace in-kind; however, once the existing small and limited inventory of analog meters has expired, UPPCO will replace in accordance with UPPCO's Non-Standard inventory at the time of expiration which may include a digital, yet non-transmitting, meter.

Q. Are the Non-Standard Meter Provision charges cost of service based?

A. Yes, and as such, to the extent the values potentially change in this instant case, the applicable charges to the Non-Standard Meter Provision will correspondingly change, as well.

Q. Is UPPCO's AMI investment consistent with the recommendations from MPSC Staff as outlined in Staff's report to the Commission in Case No. U-17000?

A. Yes. As previously cited the United Stated Energy Information Administration, over 80% of residential customers have smart meters in Michigan. Michigan clearly has taken a lead in the nation regarding the deployment of smart grid technologies to advance grid modernization. In this case, UPPCO has laid out a business case that has a simple payback of 8 years along with annual savings projected to be greater than annual costs by the year 2025. Similar to Staff, UPPCO acknowledges that a minority of customers may express concerns about smart meters and as such will be afforded an opportunity to opt-out through the use of UPPCO's Non-Standard Meter Provision, at an incremental cost. Accordingly, UPPCO has updated all associated rules and/or tariffs in order to support its AMI deployment and anticipates making other related filings regarding various regulatory and metering rules pertinent during AMI project implementation.

Q. Has UPPCO presented a business case and cost-benefit analysis regarding its AMI project consistent with the June 28^{th} Order in Case No. U-18455?

A. Yes.

Q. Will UPPCO's AMI solution resolve current estimated billing concerns?

A. Yes. The plan is that both estimated billing, along with bi-monthly meter reading, will no longer be necessary, thereby eliminating these concerns.

Q. In summary, how will customers benefit from this project?

A. UPPCO's AMI project will benefit customers through (1) eliminating the need for bimonthly estimated meter readings, (2) helping modernize the power grid which will improve system reliability by providing the means for determining when and where unplanned outages occur, allowing for quicker restoration times, (3) lower rates over the longer term through corresponding operational cost savings.

CONCLUSION

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	)	Case No. U-20276
for authority to increase retail electric rates.	)	
	)	

DIRECT TESTIMONY AND EXHIBIT A-S OF

ADRIEN M. MCKENZIE, CFA

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

September 21, 2018

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Adrien M. McKenzie, and by business address is 3907 Red River, Austin, Texas 78751.

Q. In what capacity are you employed?

A. I am President of Financial Concepts and Applications, Inc. ("FINCAP"), a firm engaged in financial, economic, and policy consulting to business and government. A further discussion of FINCAP and my role there is included in Exhibit A-A-56, pp. 1-2.

Q Please describe your educational background and professional experience.

A. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit A-A-56.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present to the Michigan Public Service Commission ("MPSC" or the "Commission") my independent evaluation of the fair and reasonable rate of return on equity ("ROE") for the jurisdictional electric utility operations of Upper Peninsula Power Company ("UPPCO" or the "Company"). In addition, I also examined the reasonableness of the Company's capital structure, considering both the specific risks faced by the Company, as well as other industry guidelines.

Q. Are you sponsoring any exhibits in this proceeding?

A. I am sponsoring the following exhibits, all of which were prepared by me or under my direction:

Exhibit No.	Description
A-56	Qualifications of Adrien M. McKenzie
A-57	Summary of Results
A-58	Regulatory Mechanisms – Proxy Group
A-59	Capital Structure
A-60	DCF Model – Proxy Group
A-61	Sustainable Growth Rate – Proxy Group
A-62	Capital Asset Pricing Model
A-63	Empirical Capital Asset Pricing Model
A-64	Risk Premium Method
A-65	Expected Earnings Approach
A-66	DCF Model – Non-Proxy Group

Q. Please summarize the information and materials you relied on to support the opinions and conclusions contained in your testimony.

A. To prepare my testimony, I referenced information from a variety of sources that would normally be relied upon by a person in my capacity. In connection with this filing, I considered and relied upon publicly available financial reports and filings, testimony of other company witnesses, and other published information relating to the Company. I also reviewed information relating generally to capital market conditions and specifically to investor perceptions, requirements, and expectations for UPPCO's utility operations. These sources, coupled with my education, training and 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.

Q. How is your testimony organized?

A. First, I summarize my conclusions and recommendations, giving special attention to the importance of financial strength and the implications of company size, capital spending levels, service area characteristics, regulatory mechanisms, and other risk factors. I also comment on the reasonableness of the Company's proposed capital structure.

Next, I review UPPCO's operations and finances. I then examine current conditions in the capital markets and their implications in evaluating a fair and reasonable ROE for UPPCO. With this as a background, I conduct quantitative analyses using well-accepted analytical models to estimate the current cost of equity for a reference group of comparable-risk utilities. These models included the discounted cash flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the empirical form of the CAPM ("ECAPM"), an equity risk premium approach based on allowed ROEs, 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, I determined that the 10.5% ROE requested by UPPCO is fair and reasonable, taking into account the specific risks for its jurisdictional utility operations in Michigan relative to its peers and the Company's requirements for financial strength. Further, consistent with the fact that utilities must compete for capital with firms outside their own industry, I corroborate my utility quantitative analyses by applying the DCF model to a group of low risk non-utility firms.

II. RETURN ON EQUITY FOR UPPCO

Q. What is the purpose of this section?

A. This section presents the support for my conclusion that the 10.50% ROE requested for UPPCO's electric utility operations in Michigan is a conservative estimate of investors' required rate of return for the Company. I discuss the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital. I analyze the impacts that company size, service area characteristics, regulatory mechanisms, and other risk factors have on the risk profile of the Company and describe how these impacts influence UPPCO's need for financial strength and its requested ROE. Finally, this section references the capital structure proposed by the Company and confirms its reasonableness.

Q. Please provide a brief description of UPPCO.

A. As discussed in greater detail later in my testimony, UPPCO provides vertically-integrated electric utility services to approximately 54,000 retail customers in Michigan's Upper Peninsula, with industrial customers accounting for a majority of the Company's sales. Over 80% of UPPCO's power requirements are met through wholesale purchases, with the remainder being supplied from company-owned hydroelectric generating facilities and two 45-year old combustion turbines.

A. Importance of Financial Strength

Q. What is the role of the ROE in setting a utility's rates?

A. 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 fair 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 its findings in *Bluefield* and establishing that the rate-setting process must produce an end-result that allows the utility a reasonable opportunity to cover its capital costs. The Court stated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. . . . By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain credit and attract capital.[2]

In summary, the Supreme Court's findings in *Hope* and *Bluefield* established that a utility's allowed ROE should 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 Supreme Court's requirements can only be met if the utility has a reasonable opportunity to actually earn its allowed ROE.[3]

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[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[3] The MPSC has consistently cited *Bluefield* and *Hope* with approval for the principles that should guide the Commission in establishing a fair ROE. *See, e.g.*, *In re Application of Consumers Energy Company*, Case No. U-17990, Order at 66 (MPSC Feb. 28, 2017) ("[i]n establishing a fair rate of return, consideration should be given to both investors and customers. The rate of return should not be so high as to place an unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise.")

While the *Hope* and *Bluefield* decisions did not establish a particular method to be followed in fixing rates, 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 and CAPM), 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.[4]

Q. Throughout your testimony you refer repeatedly to the concepts of "financial strength," "financial integrity," and "financial flexibility." Briefly describe what you mean by these terms.

A. 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 Supreme Court standards. UPPCO's plans call for a continuation of capital investments in generation, transmission and distribution systems and technology to preserve and enhance service reliability for its customers. To fund these requirements and to repay its maturing debt, UPPCO must generate adequate cash flow from operations and, access capital from external sources on a sustainable basis under reasonable terms.

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[4] This "end-result" standard has also been recognized by the Michigan Courts. In *Meridian Township v. City of East Lansing*, 343 Mich. 734 (1955), the court considered the question of what is "reasonable" in the context of a utility rate case. The court concluded that "[t]he determination of [what is reasonable] . . . is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use." 343 Mich. At 749.

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.

Q. What part does regulation play in ensuring that UPPCO has access to capital under reasonable terms and on a sustainable basis?

A. 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, particularly during times of adverse conditions. Security analysts study commission orders and regulatory policy statements to advise investors about where to put their money. As Moody's Investors Service ("Moody's") noted, "the regulatory environment is the most important driver of our outlook because it sets the pace for cost recovery."[5] Similarly, S&P Global Ratings ("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."[6]

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[5] Moody's Investors Service, "Regulation Will Keep Cash Flow Stable As Major Tax Break Ends," *Industry Outlook* (Feb. 19, 2014).
[6] S&P Global Ratings, "Assessing U.S. Investors-Owned Utility Regulatory Environments," *RatingsExpress* (Aug. 10, 2016).

Q. Do customers benefit by enhancing the utility's financial flexibility?

A. Yes. Providing an ROE that is sufficient to maintain UPPCO's ability to attract capital under reasonable terms, even in times of financial and market stress, is not only consistent with the economic requirements embodied in the U.S. Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. 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. With a service area prone to economic volatility and extreme weather, this relationship is especially important: customers benefit when the Company has the financial strength to rapidly and effectively respond in times of economic stress and natural disasters.

B. Company-Specific Risk Factors

Q. What is the purpose of this section of your testimony?

A. The cost of equity estimates developed later in my testimony are predicated on the investment risk associated with a group of publicly traded electric utilities that are situated as similarly as possible to UPPCO (the "Proxy Group"), which I use to estimate UPPCO's ROE.[7] This section compares the risks of the Proxy Group with those that investors would associate with UPPCO and evaluates the return adjustment necessary to compensate for UPPCO's greater relative risk.

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[7] The criteria used to select the Proxy Group is discussed in more detail in Section IV of my testimony.

i. Lack of Published Risk Measures

Q. Are the results of your various quantitative analyses directly applicable to UPPCO?

A. No. The cost of equity estimates developed in my testimony are predicated on the investment risk associated with the utilities in the proxy group, all of which have published risk indicators and are materially larger than the Company. These risk indicators, such as those compiled by the credit rating agencies and Value Line, provide investors with an objective benchmark to evaluate relative risk. The ability to rely on such measures in evaluating the exposure associated with a given investment has important implications for investors' risk perceptions and the utility's access to capital.

For example, many investors are restricted by federal regulations or investment guidelines from the purchase of debt securities that do not have an investment grade rating. As a result, in contrast to the firms in the Proxy Group, the lack of objective risk indicators corresponding to UPPCO complicates investors' analyses and limits the Company's access to capital. Large, publicly traded utilities enjoy improved exposure to financial markets, which enhances their ability to raise additional capital relative to smaller utilities. As a result, they are better prepared to withstand adverse events and possess greater financial flexibility to respond or adapt to changing conditions in the economy and industry.

Q. What does this imply with respect to the risks that investors would associate with UPPCO?

A. In all likelihood, this suggests that investors would view the Company's stand-alone risks as being consistent with a speculative grade credit rating, which is indicative of an entirely different risk class. Because investors require a higher rate of return to compensate them for bearing more risk, the greater investment risk implied by the

Company's stand-alone credit position suggests that the cost of equity is correspondingly higher than for the proxy group.

Q. Is this assessment confirmed by reference to confidential, non-published credit assessments?

A. Yes. While there are no published credit ratings available for the Company, Moody's has issued an unpublished credit opinion for UPPCO's immediate parent, Upper Peninsula Power Holding Company ("UPPHC"). Based on a recent review of UPPHC's credit standing, Moody's informed management on September 18, 2018 that it was downgrading UPPHC's rating from Baa3 to Ba1, which places UPPHC in the same category as speculative grade bonds.[8]

Q. What is the significance of "investment grade" versus "below investment grade"?

A. The term "investment grade" refers to a security having sufficient quality, or relatively low risk, to be suitable for certain in investment purposes, with many investors being restricted by federal regulations or investment guidelines from the purchase of debt securities that do not have an investment grade rating. There is a precipitous increase in risk associated with moving from investment grade to below investment grade securities. Credit rating differences within the investment grade range tend to reflect relatively modest gradations among fairly secure investments. Meanwhile, moving to below investment grade implies an altogether different risk plateau – one where the firm is regarded as a speculative investment. Fitch

[8] Credit rating firms, such as Moody's, use designations consisting of upper- and lower-case letters 'A' and 'B' to identify a bond's credit quality rating. 'Aaa', 'Aa', 'A', and 'Baa' ratings are considered investment grade. Credit ratings for bonds below these designations ('Ba', 'B', 'Caa', etc.) are considered speculative grade, and are commonly referred to as "junk bonds". The term "investment grade" refers to bonds with ratings in the 'Baa' category and above.

observed that when credit market conditions are unsettled, "'flight to quality' is selective within the [utility] sector, favoring companies at higher rating levels."[9] The negative impact of declining credit quality on a utility's capital costs and financial flexibility becomes more pronounced as debt ratings move down the scale from investment to non-investment grade. As the former Chairman of the New York State Public Service Commission noted in his role as spokesman for the National Association of Regulatory Utility Commissioners:

> While there is a large difference between A and BBB, there is an even brighter line between Investment Grade (BBB-/Baa3 bond ratings by S&P/Moody's, and higher) and non-Investment Grade (Junk) (BB+/Ba1 and lower). The cost of issuing non-investment grade debt, assuming the market is receptive to it, has in some cases been hundreds of basis points over the yield on investment grade securities.[10]

Q. Is there any direct capital market evidence regarding the amount of the premium investors require from a firm that is rated below investment grade?

A. Although rates of return on equity for below investment grade firms cannot be directly observed, the yields on long-term bonds provide direct evidence of the additional return that investors require to compensate for the risks associated with speculative grade credit ratings. While average yields for double-B utility bonds are not published, the yields on high-yield corporate bond indices are reported by the Federal Reserve Bank of St. Louis and summarized in the table below:

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[9] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

[10] Brown, George, "Credit and Capital Issues Affecting the Electric Power Industry," *Federal Energy Regulatory Commission Technical Conference* (Jan. 13, 2009).

TABLE 1
SPECULATIVE GRADE YIELD SPREADS

	Rating	
	BBB	**BB**
Dec-17	3.59%	4.33%
Jan-18	3.68%	4.38%
Feb-18	3.94%	4.81%
Mar-18	4.09%	4.99%
Apr-18	4.17%	4.97%
May-18	4.33%	5.16%
6-Mo. Average	3.97%	4.77%
Spread Over BBB	--	0.81%

Source: ICE Benchmark Administration Limited (IBA), ICE BofAML US Corporate Effective Yield.; https://fred.stlouisfed.org.

As shown above, the additional premium required by investors to compensate for the risks associated with a speculative grade, BB corporate debt rating (Ba on the Moody's credit rating scale) is approximately 80 basis points. Investors would undoubtedly require an even wider premium for bearing the higher risk associated with the more junior common stock of a utility with UPPCO's stand-alone risk profile.

ii. Small Size

Q. How does a small electric utility such as UPPCO compare to the large, publicly traded firms in the electric utility industry?

A. There is enormous disparity in size between UPPCO and the major participants in the electric utility industry. For example, consider the seventeen utilities making up the electric utilities in the Proxy Group. These firms dwarf the Company by any measure. Where the Proxy Group had average annual revenues in 2017 of approximately $7.8 billion and total capital of $17.2 billion, UPPCO had operating revenues of $105.7 million and total capital of $271 million.[11] Similarly, compared with UPPCO's 54,000 customers,[12] on average the firms in the Proxy Group supply utility services to 3.4 million customers.

Q. What difference does this distinction in size make?

A. 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 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.

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[11] UPPCO 2017 FERC Form 1 at 114 and 112.
[12] *Id.* at 304.

Q. Is there empirical evidence in the financial literature that a company's size affects its relative risks?

A. 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.[13] Similarly, a classic University of Kansas study demonstrated that large firms are assigned higher bond ratings than small firms with similar characteristics,[14] and there is ample empirical evidence that investors in smaller firms realize higher rates of return than in larger firms.[15] 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.

Q. What is the magnitude of the adjustment required to account for this size premium?

A. One estimate of the size premium is available from Duff & Phelps, which now reports the widely-recognized Ibbotson Associates data based on historical returns for "Low-Cap" and "Micro-Cap" stocks, in addition to its better-known data series for the S&P 500. Low-Cap companies comprise the 6th through 8th size-deciles of those stocks listed on the New York Stock Exchange, American Stock Exchange, and NASDAQ, while Micro-Cap stocks represent the 9th through 10th size-deciles.

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[13] Eugene F. Fama and Kenneth R. French, "The Cross-Section of Expected Stock Returns", *The Journal of Finance* (June 1992), p. 429.
[14] George E. Pinches, J. Clay Singleton, and Ali Jahankhani, "Fixed Coverage as a Determinant of Electric Utility Bond Ratings", *Financial Management* (Summer 1978).
[15] See for example Rolf W. Banz, "The Relationship Between Return and Market Value of Common Stocks", *Journal of Financial Economics* (September 1981) at 16.

The individual firms in the Low-Cap group have market capitalizations at or below about $2.8 billion but greater than $658 million, with the market capitalization of Micro-Cap stocks falling between approximately $2.5 million and $658 million.[16] These smaller companies have historically earned higher rates of return than the large companies comprising the S&P 500. For the 1926 to 2017 period, Duff & Phelps reported a size premium in excess of the return implied by the CAPM of 166 basis points for the Low-Cap sector, and 346 basis points for Micro-Cap companies.[17]

Q. Is there any other evidence that quantifies the difference in the cost of equity between large and small utilities?

A. Yes. 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:[18]

> The smaller deciles show returns not fully explainable by the CAPM. The difference in risk premium (realized versus CAPM) grows larger as one moves from the largest companies in decile 1 to the smallest in decile 10. The difference is especially pronounced for deciles 9 and 10, which contain the smallest companies.[19]

The study went on to conclude that a publicly traded utility with a market capitalization of $1.0 billion would require a small company premium of approximately 130 basis points above the rate of return for larger firms.

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[16] Duff & Phelps Cost of Capital Navigator, 2018 Cost of Capital: Annual U.S. Guidance and Examples, (Chapter 7, pp. 10-11, and CRSP Deciles Size Study).
[17] *Id.*
[18] As discussed later in my testimony, "beta" is a measure of investment risk that measures the variability of a stock's price relative to fluctuations in the market as a whole.
[19] Annin, Michael, "Equity and the Small-Stock Effect", Public Utilities Fortnightly (Oct. 15, 1995), at 43.

Q. What does this evidence imply with respect to the ROE for UPPCO specifically?

A. The additional return attributable to the significant distinction in size between UPPCO and the Proxy Group can be estimated by reference to the relative size premiums quantified by Duff & Phelps for their respective market capitalizations. Because UPPCO does not have publicly traded common stock, its implied market capitalization was estimated by multiplying the Company's total common equity of approximately $163.0 million[20] by the average market-to-book ratio for the Proxy Group of 1.97 times. This implies a market capitalization for UPPCO of $321.1 million and corresponds to the 9th decile of the publicly-traded firms, which had market capitalizations ranging from $299.4 to $657.7 million and a size premium of 2.48%.[21]

Meanwhile, the average market capitalization for the Proxy Group of $12.4 billion corresponds to the 2nd decile of Duff & Phelps' market study and a size premium of 55 basis points.[22] Subtracting the size premium associated with the Proxy Group of 55 basis points from the 248 basis point premium for a firm in the 9th decile results in an implied size adjustment of 193 basis points to reflect the additional risks of UPPCO relative to the much larger electric utilities in the proxy group.

iii. Economically Vulnerable Service Area

Q. Please describe UPPCO's service area.

A. UPPCO's service territory is geographically isolated in a relatively vulnerable economic region with exposure to cyclical commodity-based industries. It serves

[20] UPPCO 2017 FERC Form 1 at 112.
[21] Duff & Phelps Cost of Capital Navigator, 2018 Cost of Capital: Annual U.S. Guidance and Examples, (Chapter 7, pp. 10-11, and CRSP Deciles Size Study).
[22] *Id.*

approximately 54,000 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.[23] The potential for uncertain and extreme weather increases the complexities of operating in such an environment.

Q. Do weather-related risks have implications for UPPCO's financial position?

A. Yes. In addition to increasing UPPCO's overall risk profile (which in turn has a direct impact on requirements for financial strength), the service territory's exposure to adverse weather impacts has a direct impact on the Company's need for financial strength. UPPCO must maintain ready access to larger reserves of credit and liquidity than most other utilities. Given the high value that UPPCO and its customers place on service availability and reliability, rapid restoration of service after a weather-induced outage is the Company's highest priority. UPPCO must be able to marshal both internal and external resources on a massive scale very quickly, and this leads to large needs for credit and liquidity. Restoration efforts must be funded long before the recovery of 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.

Q. What other factors specific to UPPCO's service area warrant consideration?

A. UPPCO's service area is characterized by a high concentration of sales to industrial customers relative to the companies in the Proxy Group. As illustrated in the

[23] https://www.uppco.com/our-company/about-us/facts/ (accessed June 28, 2018).

following table, the Company has nearly twice the degree of sales to industrial customers as firms in the proxy group:

TABLE 2
INDUSTRIAL REVENUE CONCENTRATION

Company	Industrial to Total Energy Sales	Company	Industrial to Total Energy Sales
Algonquin Pwr & Util (a)	21.6%	Exelon Corp.	40.2%
Ameren Corp.	20.5%	FirstEnergy Corp.	35.2%
AVANGRID, Inc. (b)	24.4%	IDACORP, Inc.	20.0%
Black Hills Corp.	24.3%	NorthWestern Corp.	23.6%
CMS Energy Corp. (c)	26.2%	Otter Tail Corp. (e)	38.0%
DTE Energy Co.	22.0%	PNM Resources	18.9%
El Paso Electric Co.	10.5%	Pub Sv Enterprise Grp. (f)	9.0%
Emera Inc. (d)	10.8%	Sempra Energy	11.6%
Entergy Corp.	38.4%	**Average - Utility Group**	**23.3%**
		UPPCO	**45.8%**

Sources:
2017 FERC Form 1 for UPPCO; 2017 SEC Form 10-K for proxy companies except:
(a) 2015 SEC Form 10-K for Empire District Electric Co.
(b) 2016 FERC Form 1 for New York State Electric & Gas Corp., Rochester Gas & Electric Corp., and The United Illuminating Co.
(c) 2016 FERC Form 1 for Consumers Energy Co.
(d) 2016 FERC Form 1 for Emera Maina; 2015 SEC Form 10-K for Tampa Electric Co.
(e) 2016 FERC Form 1 for Otter Tail Power Co.
(f) 2016-2017 PSEG Investor Fact Book.

Almost 46% of the Company's total energy sales are to industrial customers[24]. 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 more risky 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.

[24] UPPCO 2017 FERC Form 1 at 304.

Q. Can you give specific examples of the risks associated with UPPCO's volatile industrial customer base?

A. Forest products and mining are two of the predominant industries served by the Company. These are cyclical, commodity-based businesses that remain under heavy economic pressure. Indeed, UPPCO has experienced two customer bankruptcies in the paper and mining sectors within the last two years. 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, UPPCO's third largest customer, Enbridge Inc., operates a petroleum pipeline under the Straits of Mackinac, which is under threat of closure due to pipeline integrity concerns. In 2017, UPPCO wrote off $730,000 in bad debt charges;[25] losing the Enbridge account would generate approximately $2.6 million in additional bad debt charges.

iv. Regulatory Mechanisms

Q. Did you consider the implications of cost recovery mechanisms in evaluating a fair ROE for UPPCO?

A. Yes. Adjustment mechanisms and cost trackers have become increasingly prevalent in the utility industry in recent years. In response to the increasing risk sensitivity of

[25] UPPCO 2017 FERC Form 1 at 450.1.

investors to uncertainty over fluctuations in costs and the importance of advancing other public interest goals such as reliability, energy conservation, integration of renewables and safety, utilities and their regulators have sought to mitigate some of the cost recovery uncertainty and align the interests of utilities and their customers through a variety of adjustment mechanisms. Based largely on the expanded use of ratemaking mechanisms to address operational risks and investment recovery, Moody's upgraded most regulated utilities in January 2014.[26] This is consistent with the view that investors perceive the impact of regulatory mechanisms to be a positive industry-wide factor. Just as a rising tide lifts all boats, ratemaking mechanisms have had an across-the-board impact on risk perceptions for virtually all utilities.

Reflective of this trend, a 2017 study by Regulatory Research Associates (an arm of S&P) recognized that companies in the electric utility industry operate under a wide variety of cost adjustment mechanisms, in addition to the standard fuel cost recovery clauses that they all have.[27] These enhanced tools encompass riders to recover bad debt expenses, certain taxes and fees, post-retirement employee benefit costs and transmission-related charges, as well as adjustment clauses designed to address rising capital investment outside of a traditional rate case and the impact of conservation programs. Mechanisms that separate utility revenue from volumetric sales are also common. Regulatory Research Associates concluded that, "some form of decoupling is in place in the vast majority of the jurisdictions."[28] Moreover, in response to the possibility of substantial costs associated with new environmental

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[26] Moody's Investors Service, "US utility sector upgrades driven by stable and transparent regulatory frameworks," *Sector Comment* (Feb. 3, 2014).
[27] Regulatory Research Associates, "Adjustment Clauses, A state-by-state overview," *RRA Regulatory Focus* (Sep. 12, 2017).
[28] *Id.*

compliance measures, adjustment mechanisms designed to allow for recovery of these costs outside a general rate case have also become increasingly prevalent.

Q. Have similar regulatory mechanisms been approved for UPPCO?

A. Yes, to some extent. The Company operates under a standard fuel and purchased power cost recovery mechanism and determines its proposed cost of service based on a future test year. In addition, it has distribution expense and distribution capital trackers. However, these trackers function as "one-way" trackers. That is, if the Company spends more than the approved amount, it is expected to absorb the additional amount as a cost of doing business. This mechanism could deny the Company the opportunity to recover its reasonable business-related costs.

Q. Do the Company's regulatory mechanisms set it apart from the firms in the proxy group you used to estimate the cost of equity?

A. No. A broad array of adjustment mechanisms is also available to the companies in my proxy group of electric utilities.[29] As summarized on page 1 of Exhibit A-A-58, these mechanisms are ubiquitous and wide ranging. For example, 9 of the 17 firms in the Proxy Group have utilities that operate under some form of decoupling mechanism that accounts for the impact of various factors affecting sales volumes and revenues. Most of the companies also have adjustment clauses to effectively recover certain capital expenditures, conservation program impacts, renewable energy outlays, environmental compliance costs, and transmission-related charges.

[29] Because this information is widely referenced by the investment community, it is also directly relevant to an evaluation of the risks and prospects that determine the cost of equity.

Between them, the 17 companies included in the Proxy Group own 44 separate operating companies.[30] As detailed on pages 2-4 of Exhibit A-A-58, 26 of these 44 operating utilities benefit from capital cost trackers that allow for recovery of new capital investment in generation facilities or other infrastructure outside of a traditional rate case. In addition, almost half of all the operating utilities[31] operate under a full or partial decoupling mechanism that accounts for various factors affecting sales volumes and revenues and 35 operate in jurisdictions that allow for some form of future test period. Other mechanisms automatically recover storm, pension, and bad debt costs, along with various taxes and franchise fees.

Q. What do these characteristics imply with respect to the Company's risks relative to other utilities in general?

A. In an effort to attenuate regulatory lag and attrition, adjustment mechanisms and cost trackers similar to those available to UPPCO have been increasingly prevalent in the utility industry in recent years. Investors recognize that the use of adjustment mechanisms and future test years is widely prevalent in the utility industry and consider the relative impact of these provisions in forming their expectations and risk perceptions for the firms in the Proxy Group. While regulatory mechanisms approved for the Company are comparable to those listed for the Proxy Group, investors would also consider the unfairness associated with the "one-way" nature of UPPCO's expense and capital trackers.

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[30] There are 44 operating companies or major divisions represented on pages 2-4 of Exhibit A-AMM 4 (22 integrated electric companies and 22 delivery-only companies).

[31] Of the 44 operating companies, 20 of them have some form of decoupling mechanism.

v. Other Risk Factors

Q. What other unique risk factors does UPPCO face?

A. UPPCO's earned return has consistently fallen below its authorized ROE. Part of the reason for this situation is related to the "revenue offset" that the Company agreed to in the docket approving its divestiture from Integrys Energy Group in 2014.[32] This offset mechanism is discussed in the testimony of UPPCO witness Mr. Haehnel. Allowing for this offset, the Company has still suffered from chronic under-earning. As Mr. Haehnel discusses, the Company anticipates that, absent modifications to the revenue offset mechanism, it will significantly under-earn its allowed rate of return going forward. In regulatory parlance, this under-earning is commonly referred to as "attrition."

Q. Please describe the concept of attrition as it relates to utility ratemaking.

A. Attrition refers to a shortfall between a utility's actual return and the allowed return approved by regulators. It occurs when the assumptions regarding sales, costs, and rate base used to establish rates do not produce revenues that reflect the actual costs incurred to serve customers during the period that rates are in effect. For example, if external factors are driving costs to increase more than revenues, then the rate of return will fall short of the allowed return even if the utility is operating efficiently. Similarly, when growth in the utility's investment outstrips the rate base used for ratemaking, the earned rate of return will fall below the allowed return through no fault of the utility's management. These imbalances can be exacerbated due to regulatory lag between the time when the data used to establish rates is measured and the date when the rates go into effect.

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[32] Case No. U-17564, Final Order dated June 6, 2014.

Q. Why is it necessary to address the impact of attrition?

A. The revenue requirements used to establish a utility's rates are customarily based on data for a "test year," which presumably provides a representative basis to determine the Utility's costs of providing service and the billing determinant necessary to convert those costs into customer rates. Investors are most concerned with the return they can reasonably expect to earn in the future, not simply the allowed ROE or what they might expect in theory if the test year were to accurately reflect actual results. To be fair to investors and to benefit customers, a regulated utility must have an opportunity to actually earn a reasonable return that will maintain financial integrity, facilitate capital attraction, and compensate for risk. In other words, it is the end result in the future that determines whether or not the *Hope* and *Bluefield* standards are met.

Q. Has the investment community recognized the implications of attrition in evaluating the risks faced by utilities?

A. Yes. S&P observed that its analysis "centers on the utility's ability to consistently earn the authorized ROE,"[33] and noted that, "The regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[34] S&P observed that the benefits of regulatory mechanisms could be undermined without constructive outcomes in rate

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[33] Standard & Poor's Corporation, "Key Credit Factors For The Regulated Utilities Industry," *RatingsDirect* (Nov. 19, 2013) at 12 (emphasis added). *See also,* Standard & Poor's Corporation, "Assessing U.S. Utility Regulatory Environments," RatingsDirect (Nov. 7, 2008) (concluding that, "Notably, the analysis does not revolve around "authorized" returns, but rather on actual earned returns. We note the many examples of utilities with healthy authorized returns that, we believe, have no meaningful expectation of actually earning that return because of rate case lag, expense disallowances, etc.").

[34] Standard & Poor's Corporation, "Utilities: Key Credit Factors For The Regulated Utilities Industry," *Criteria* (Nov. 19, 2013).

cases, and noted that, "Our assessment of whether the company is improving its regulatory outcomes will focus on whether its earned ROE is approaching authorized."[35] Similarly, Moody's concluded:

> We evaluate the framework and mechanisms that allow a utility to recover its costs and investments and earn allowed returns. We are less concerned with the official allowed return on equity, instead focusing on the earned returns and cash flows.[36]

The Value Line Investment Survey ("Value Line") summarizes these sentiments:

> As we often point out, the most important factor in any utility's success, whether it provides electricity, gas, or water, is the regulatory climate in which it operates. Harsh regulatory conditions can make it nearly impossible for the best run utilities to earn a reasonable return on their investment.[37]

Absent other changes to the regulatory paradigm that allow the utility to better match its revenues with its costs, attrition warrants a higher authorized ROE in order to satisfy the end-result test of *Hope* and *Bluefield.*

Q. How is UPPCO proposing to remedy these deficiencies?

A. As discussed in the testimony of UPPCO witness Mr. Haehnel, the Company is requesting certain modifications to the revenue offset process, which seek to address UPPCO's anticipated inability to earn its authorized ROE. These modifications include lowering the revenue credit from Case No. U-17564 from $4,333,333 to $2,584,802.

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[35] Standard & Poor's Corporation, "Hawaiian Electric Co. Inc.," *RatingsDirect* (Nov. 21, 2011).
[36] Moody's Investors Service, "Electric Utilities Face Challenges Beyond Near-Term," *Industry Outlook* (Jan. 2010).
[37] Value Line Investment Survey, Water Utility Industry (January 13, 2017) at p. 1780.

Q. In the event these requested modifications are not approved, would it be reasonable to consider the impact of UPPCO's exposure to attrition?

A. Yes. If the equity capital that is dedicated to utility public service does not have an opportunity to earn a return commensurate with that available from alternatives of equivalent risk in the capital markets, investors are not being adequately compensated for the use of their money and bearing risk. The concept of an attrition adjustment is directly analogous to "Kentucky windage," where a marksman compensates for wind or motion of the target by aiming at a point other than the target's position. An upward adjustment to the allowed ROE used to establish UPPCO's revenue requirements and rates would produce correspondingly higher revenues. These additional revenues would increase the likelihood that UPPCO's actual earned rate of return would be closer to the unadjusted cost of equity determined in this proceeding, thus granting investors an opportunity to actually earn their required rate of return.

Setting rates at a level that considers the impact of attrition and allows the utility an opportunity to actually earn its authorized ROE is consistent with fundamental regulatory principles. Central to the determination of reasonable rates for utility service is the notion that owners of public utility properties are protected from confiscation. The Supreme Court standards established by *Hope* and *Bluefield* dictate that the end result test must be applied to the actual returns that investors expect if they put their money at risk to finance utilities.

Absent other changes to the regulatory paradigm that allow the utility to better match its revenues with its costs, this end result can only be achieved for UPPCO if the allowed return is sufficient to offset the impact of attrition. That end result would maintain the utility's financial integrity, ability to attract capital and offer investors fair compensation for the risk they bear. Whatever the Commission ultimately determines to be investors' required return, the only way to achieve that end result is to set the ROE at a higher level that is sufficient to give the Company an opportunity to actually earn investors' required rate of return in the future. Accordingly, if the requested changes to the revenue offset are not approved, the anticipated shortfall between UPPCO's actual earned returns and its authorized ROE supports an upward adjustment to the Company's ROE.

Q. Does the Company's power supply mix add to the Company's risk profile?

A. Yes. The Company's primary source of energy supply is through hydro generation and purchases in the wholesale market. In 2017, hydro sources supplied 18.8% of the Company's total energy needs and purchases provided 81.1%.[38] Both of these sources entail added risk. While hydropower confers advantages in terms of fuel cost savings and diversity, reduced hydroelectric generation due to below-average water conditions may force UPPCO to rely even more heavily on wholesale power markets 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.[39]

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

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[38] UPPCO 2017 FERC Form 1 at 401a.

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

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.

Q. What other considerations are relevant in evaluating a fair ROE for UPPCO?

A. Income taxes, like other expenses necessary to provide utility service, are one component of the cost of service. Amendments to the tax code stemming from the Tax Cuts and Jobs Act ("TCJA"), which are reflected in the revenue requirements requested by UPPCO is this case, serve to reduce rates for customers, but they also have detrimental implications for the financial strength of regulated utilities. By lowering the income tax allowance reflected in rates, eliminating the benefits of bonus depreciation, and requiring the eventual refund of excess accumulated deferred income taxes, the TCJA is widely expected to result in impaired cash flow and undermine credit metrics for utilities.

For example, Moody's recently revised its ratings outlook for 24 utilities from "stable" to "negative," and one utility from "positive" to "stable," due to the potential impact of the TCJA on cash flows and financial integrity.[40] As Moody's observed:

> Investors-owned utilities' rates, revenue and profits are heavily regulated. The rate regulators allow utilities to charge customers based on a cost-plus model, with tax expense being one of the pass-through items. In practice, regulated utilities collect revenues from customers based on book tax expense but typically pay much less tax in cash. Under the new tax regime, utilities will collect less revenue

[40] Moody's Investors Service, "Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform." *Ratings Action* (Jan. 19, 2018).

> associated with tax expenses and pay out more cash tax, squeezing its cash flows.[41]

Moody's noted that supportive regulatory actions, in the form of timely cost recovery and constructive determinations regarding capital structure and ROE, would be important to stave off deterioration in credit metrics and potential ratings downgrades.[42] Similarly, S&P concluded that the TCJA will likely have negative rating consequences for many rate-regulated utilities:

> The impact of tax reform on utilities is likely to be negative to varying degrees depending on a company's tax position going into 2018, how its regulators react, and how the company reacts in return. It is negative for credit quality because the combination of a lower tax rate and the loss of stimulus provisions related to bonus depreciation or full expensing of capital spending will create headwinds in operating cash-flow generation capabilities as customer rates are lowered in response to the new tax code. . . . Regulators must also recognize that tax reform is a strain on utility credit quality, and we expect companies to request stronger capital structures and other means to offset some of the negative impact.[43]

As S&P concluded, "The impact could be sharpened or softened by regulators depending on how much they want to lower utility rates immediately instead of using some of the lower revenue requirement from tax reform to allow the utility to retain the cash for infrastructure investment or other expenses."[44]

Fitch Ratings Inc. ("Fitch") also highlighted its expectation that the TCJA "has negative credit implications for regulated utilities and utility holding companies

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[41] Moody's Investor Service, "Tax reform is credit negative for sector, but impact varies by company," *Sector Comment* (Jan. 24, 2018).

[42] Moody's Investors Service, "Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform." *Ratings Action* (Jan. 19, 2018). *Id.*

[43] S&P Global Ratings, "U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound," *RatingsDirect* (Jan. 24, 2018).

[44] *Id.*

over the short to medium term."[45] As Fitch observed, "Absent mitigating strategies on the regulatory front, this is expected to lead to weaker credit metrics and negative ratings actions,[46] and an "[i]increase in authorized equity ratio and/or return on equity" would be one tool to support utilities' credit standing.[47] Coupled with the need to undertake significant new capital investment, the implications of the TCJA heighten the importance of supportive regulatory actions in order to maintain utilities' financial integrity and access to capital.

Q. What is Moody's current outlook on electric utilities and the impacts of the TCJA?

A. On June 18, 2018, Moody's announced that it was changing the utility sector outlook from stable to negative.[48] Moody's stated that:

> The change in outlook primarily reflects a degradation in key financial credit ratios…The change in outlook also reflects uncertainty with respect to the timing and extent of potential changes in regulatory recovery provisions, authorized returns and equity layers or self-help options by individual companies in response to lower cash flow."[49]

> The change in fundamental sector outlook reflects a declining financial trend, which is a function of higher holding company debt levels incurred in the past few years and a lower deferred tax contribution to cash flow going forward due to tax reform.[50]

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[45] Fitch Ratings Inc., "Tax Reform Impact on the U.S. Utilities, Power & Gas Sector," *Special Report* (Jan. 24, 2018).
[46] *Id.*
[47] *Id.*
[48] Moody's Investors Service, "Announcement: Moody's changes the US regulated utility sector outlook to negative from stable." (June 18, 2018).
[49] *Id.*
[50] *Id.*

Q. Have S&P or Fitch taken immediate actions to lower the outlook or ratings for issuers in the utility industry?

A. No. Neither agency has announced an industry-wide reappraisal of credit standing; rather, they have indicated that their evaluation will reflect a "wait-and-see" approach, predicated in large part on the regulatory response for individual utilities. As Fitch noted, "If Fitch sees a credible path for credit metrics to be restored commensurate with the existing rating level, no rating actions may be warranted."[51] The implications of the TCJA heighten the importance of supportive regulatory actions in order to maintain UPPCO's financial integrity and access to capital.

Q. 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.

A. While faced with added risks related to its small size, economically vulnerable service area, lack of efficient regulatory mechanisms, inability to earn its allowed return, potentially volatile power supply mix, and fallout from the TCJA, 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

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[51] Fitch Ratings Inc., "Tax Reform Impact on the U.S. Utilities, Power & Gas Sector," *Special Report* (Jan. 24, 2018).

infrastructure and take whatever actions are required to ensure a reliable energy supply.[52] By the same token, customers and the service area economy suffer when the utility is unable to attract necessary capital.

C. Recommended ROE

Q. What are your findings regarding the 10.5% ROE requested by UPPCO?

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital under reasonable terms, I determined that 10.5% is a conservative estimate of investors' required ROE for UPPCO. The results of my analyses are shown on Exhibit A-57, with the support for my conclusion being summarized below:

- In order to reflect the risks and prospects associated with UPPCO's jurisdictional utility operations, my analyses focused on a proxy group of 17 other electric utilities.
- 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 fair and reasonable ROE for UPPCO, as well as referencing the expected earnings approach.
- Widespread expectations for higher interest rates emphasize the need to consider the impact of projected bond yields in evaluating the results of these quantitative methods.
- As summarized on Exhibit A-57, considering the results of these analyses, and giving less weight to extremes at the high and low ends of the range, I concluded that the cost of equity for the proxy group of utilities is in the 9.8% to 10.8% range.
- An ROE from the upper end of my recommended range is warranted for UPPCO because of the Company's greater investment risks relative to 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

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[52] The importance of a supportive ROE is heightened by UPPCO's large capital expenditure program to enhance reliable service to customers.

wholesale power costs, its high dependence on industrial load, and its lack of economies of scale.

- The Company lacks published credit ratings or other measures of investment risk, which heightens investors' relative risk perceptions and complicates UPPCO's access to capital, and implies a higher rate of return.
  - While UPPCO has no independent credit ratings, UPPHC's unpublished private placement rating of Ba1 from Moody's falls below the investment grade scale.
  - Reference to published bond yields provides an objective measure of the additional return required to compensate for the higher risk associated with UPPCO. Investors currently require approximately 80 basis points more to hold Ba-rated corporate bonds versus those rated Baa.
  - Because the risk exposure of common equity investors is greater than for bondholders, bond yield spreads underestimate the additional return required by common stockholders to compensate for the greater risk of a Ba rating, versus a utility rated Baa.
- There is enormous disparity in size between UPPCO and the electric utilities in the proxy group used to estimate the cost of equity, and it is well established that smaller firms are more risky than larger firms.
  - The results of widely-recognized financial research indicates a minimum size adjustment in the range of approximately 170 to 350 basis points to reflect the additional risks of UPPCO relative to the much larger electric utilities in the proxy group.
- UPPCO's large capital expenditure program relative to its size and exposure to attrition highlight the need for regulatory support.

- As reflected in the testimony of Company witness Mr. Kates, UPPCO is requesting a fair ROE of 10.5%, which represents a conservative ROE for the Company.

Q. What other specific factors should be considered in weighing the quantitative results and evaluating the recommended ROE range?

A. Current capital market conditions continue to reflect the impact of unprecedented policy measures taken in response to dislocations in the economy and financial markets stemming from the Great Recession and are not representative of what is likely to prevail over the near-term future. As a result, the DCF results for utilities may be affected by potentially unrepresentative financial inputs. As FERC concluded:

> [W]e also understand that any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula, including those produced by historically anomalous capital market conditions. Therefore, while the DCF model remains the Commission's preferred approach to determining allowed rate of return, the Commission may consider the extent to which economic anomalies may have affected the reliability of DCF analyses …[53]

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

> There are three principal reasons for our unwillingness to place a great deal of weight on the results of any DCF analysis. One is . . . the failure of the DCF model to conform to reality. The second is the undeniable fact that rarely if ever do two expert witnesses agree on the terms of a DCF equation for the same utility – for example, as we shall see in more detail below, projections of future dividend cash flow and anticipated price appreciation of the stock can vary widely. And, the third reason is that the unadjusted DCF result is almost always well below what any informed financial analysis would regard as defensible, and therefore require an upward adjustment based largely on the expert witness's judgment. In these circumstances, we find it difficult to regard the results of a DCF computation as any more than suggestive.[54]

In this light, it is important to consider alternatives to the DCF model. As shown in Exhibit A-57, alternative risk premium models (*i.e.*, the CAPM, ECAPM, and utility

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[53] Opinion No. 531, 147 FERC ¶ 61,234 at P 41 (2014).
[54] *Ind. Michigan Power Co.*, Cause No. 38728, 116 PUR4th, 1, 17-18 (IURC 8/24/1990).

risk premium approaches) produce ROE estimates that generally exceed the DCF results. My expected earnings approach corroborated these outcomes.

Q. Have such alternative ROE methods been accepted by other regulators?

A. Yes. In Opinion 551, issued September 28, 2016, FERC reiterated its support for several of the very same methodologies relied on in my testimony. For example, FERC determined:

> For the reasons discussed below, we conclude that the record in this proceeding demonstrates the presence of unusual capital market conditions, such that we have less confidence that the central tendency of the DCF zone of reasonableness (the midpoint in this case) accurately reflects the equity returns necessary to meet *Hope* and *Bluefield*.[55]

> Rather, that finding supports a consideration of other cost of equity estimation methodologies in determining whether mechanically setting the ROE at the central tendency satisfies the capital attraction standards of *Hope* and *Bluefield*.[56]

> We therefore find it necessary and reasonable to consider additional record evidence, including evidence of alternative methodologies and state-commission approved ROEs, to gain insight into the potential impacts of these unusual capital market conditions on the appropriateness of using the resulting midpoint.[57]

The "alternative methodologies" referred to above include the CAPM, utility risk premium, and expected earnings approaches summarized on Exhibit A-57. After considering the results of these methods, FERC established an ROE for electric transmission services at the middle of the upper half of the DCF range, or 10.32%.[58]

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[55] Opinion No. 551, 156 FERC ¶ 61,234 at P 119 (2016).
[56] *Id.* at P 120.
[57] *Id.* at P 122.
[58] *Id.* at P 9.

Q. What did the DCF results for your select group of non-utility firms indicate with respect to your evaluation?

A. Average DCF estimates for a low-risk group of firms in the competitive sector of the economy ranged from 11.2% to 11.9%, and averaged 11.4%. While I did not base my recommendation directly on these results, they confirm that an ROE of 10.5% falls in a reasonable range to maintain UPPCO's financial integrity, provide a return commensurate with investments of comparable risk, and support the Company's ability to attract capital.

D. Capital Structure

Q. What is the common equity ratio in UPPCO's proposed capital structure?

A. The Company's capital structure is discussed in the testimony of Company witness Mr. Kates. As summarized there, the common equity component of the capital sources used to compute the overall rate of return for UPPCO 58.79%.

Q. How does this compare to the average equity ratios maintained by the Proxy Group?

A. As shown on page 1 of Exhibit A-59, common equity ratios for the individual firms in the Proxy Group ranged from a low of 15.0% to a high of 73.7% at year-end 2017, and averaged 44.9%. Meanwhile, the three-to-five year forecasts published by the Value Line Investment Survey ("Value Line") result in an average common equity ratio of 47.2% for the Proxy Group, with the individual equity ratios ranging from 33.0% to 63.5%.

Q. What capitalization ratios are maintained by other utility operating companies?

A. Pages 2-3 of Exhibit A-59 display capital structure data at year-end 2017 for the group of electric utility operating companies owned by the firms in the Proxy Group used to estimate the cost of equity. As shown there, common equity ratios for these utilities ranged from 44.3% to 74.6% and averaged 53.3%.

Q. What other factors do investors consider in their assessment of a company's capital structure?

A. Utilities are facing significant capital investment plans, uncertainties over accommodating future environmental mandates, and ongoing regulatory risks. Coupled with the potential for turmoil in capital markets, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain environment. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, even during times of adverse capital market conditions.

In addition, depending on their specific attributes, purchased power agreements or other contractual obligations that require the utility to make specified payments may be treated as debt in evaluating the Company's financial risk. Because investors consider the debt impact of such fixed obligations in assessing a utility's financial position, they imply greater risk and reduced financial flexibility. Unless the utility takes action to offset this additional financial risk by maintaining a higher equity ratio, the resulting leverage will weaken its creditworthiness and imply greater risk.

Q. What equity level was authorized for the Company in its last case before the Commission?

A. In its last case, UPPCO was authorized to include an equity level of 55.3% in its regulatory capital structure.[59]

Q. What did you conclude regarding the reasonableness of UPPCO's requested capital structure?

A. Based on my evaluation, I conclude that the capital structure requested by UPPCO represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return. Although the common equity ratio is somewhat higher than the historical and projected averages maintained by the Proxy Group, it is well within the range of individual results, consistent with the capitalization maintained by other utility operating companies, and reflects the lower financial leverage necessary to accommodate higher expected capital expenditures.

While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well as its specific needs to access the capital markets. UPPCO's proposed capital structure reflects the Company's ongoing efforts to maintain its credit standing and support access to capital on reasonable terms. The reasonableness of the Company's capital structure is reinforced by the ongoing uncertainties associated with the utility industry and the importance of supporting continued system investment, even during times of adverse industry or market conditions.

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[59] Michigan Public Service Commission, Case No. U-17895 at 11-12.

III. FUNDAMENTAL ANALYSES

Q. What is the purpose of this section?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews the operations and finances of UPPCO. In addition, it examines conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a fair rate of return.

A. Upper Peninsula Power Company

Q. Briefly describe UPPCO.

A. UPPCO is a vertically-integrated electric utility encompassing the electric generation, transmission, and distribution functions. As noted above, UPPCO provides service to approximately 54,000 electric retail electric customers consisting of residential, commercial, industrial, and government entities. The Company's service territory covers most of Michigan's Upper Peninsula.

For 2017, UPPCO's total kilowatt hour sales distribution consisted of 32.7% residential, 19.2% commercial, 45.8% industrial, and 1.8% governmental and sales for resale.[60] 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 2017 peak load of 134 MW occurred on June 12[61] and was met with hydro and purchased capacity. As noted earlier, its energy supply mix consists primarily of hydro (18.8%) and purchased energy (81.1%) sources.

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[60] UPPCO 2017 FERC Form 1 at 304. In 2017, UPPCO's total electric sales revenue consisted of 53.5% residential, 23.2% commercial, 20.9% industrial, 2.4% governmental and sales for resale.
[61] *Id.* at 401b.

UPPCO's total 2017 operating revenues of approximately $105.7 million and total assets at year-end 2017 were $351.7 million.[62]

Q. Where does UPPCO obtain the capital used to finance its investment in utility plant?

A. As a wholly-owned subsidiary, UPPCO's common equity capital is provided by UPPHC. UPPHC is, in turn, a wholly-owned subsidiary of Lake AIV, L.P., an entity operated, managed and majority owned by Basalt Infrastructure Partners, a private equity firm. Lake AIV, L.P. was formerly known as BBIP AIV and Basalt Infrastructure Partners was formerly known as Balfour Beatty Infrastructure Partners (BBIP).

Q. What credit ratings are assigned to UPPCO?

A. UPPCO does not issue debt under its own name and does not have a credit rating.

Q. Does the fact that UPPCO is owned by a holding company in any way alter the standards that underlie the determination of a fair ROE for the Company?

A. No. While the Company has no publicly traded common stock and UPPHC is UPPCO's only shareholder, this does not change the standards governing the determination of a fair ROE for the Company. Ultimately, the common equity that is required to support UPPCO's utility operations must offer investors a rate of return that is competitive with other risk-comparable alternatives. As the Supreme Court noted in *Hope*, "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[63] At the

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[62] *Id.* at 114 and 111.
[63] *Hope*, 320 U.S. 603.

time of the rate case at issue in the Supreme Court's decision, Hope Natural Gas Company ("Hope") was a subsidiary of Standard Oil Company of New Jersey (the predecessor of ExxonMobil).[64] The standard of a fair rate of return articulated in the *Hope* case did not relate to the parent, but to the utility. Hope was the entity that undertook the utility obligations and the benchmark for the adequacy of returns was the end result for the utility, not for Standard Oil.

The logic underlying the Supreme Court's determination is consistent with financial principles, which hold that the required rate of return is determined by the risk of the investment, and not by the manner in which the investment is financed. In other words, the cost of capital is dependent upon the use of the funds and not the source of the funds. As noted in New Regulatory Finance, "…an investment's required return depends on its particular risks."[65] UPPCO must compete with other investment opportunities and unless there is a reasonable expectation that investors will have the opportunity to earn returns commensurate with the underlying risks, capital will be allocated elsewhere, the Company's financial integrity will be weakened, and investors will demand an even higher rate of return. Providing UPPCO with the opportunity to earn an ROE that reflects its specific risk exposures is a necessary ingredient in ensuring reliable service at reasonable cost.

Q. Does UPPCO anticipate the need for additional capital going forward?

A. Yes. UPPCO will require capital investment to provide for necessary maintenance and replacements of its utility infrastructure.

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[64] John D. Rockefeller's Standard Oil of New Jersey formed Hope in 1898. Standard Oil's natural gas subsidiaries (including Hope) were eventually spun off as Consolidated Natural Gas Company, which was ultimately acquired by Dominion Resources, Inc. in 2000.

[65] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* at 528 (2006).

B. Outlook for Capital Costs

Q. Please summarize current capital market conditions?

A. Current capital market conditions continue to be affected by the Federal Reserve's unprecedented monetary policy actions, which were designed to push interest rates to historically and artificially low levels in an effort to support economic growth and bolster employment. More recently, investors have faced renewed volatility as capital markets have responded to uncertainties regarding geopolitical tensions,[66] the implications of an expanding economy at or near full employment, indications of price pressures and wage gains, coupled with the massive fiscal stimulus under the TCJA. While the underlying bull market in stocks has continued, the underlying risks and volatility have been exacerbated by concerns over the implications of the Trump Administration's tariff policies, which have stoked fears over the potential for an escalating international trade war.

Q. Has there been a fundamental shift in Federal Reserve monetary policies?

A. No. While the Federal Reserve's long-anticipated moves to increase the federal funds rate represent a step towards implementing the process of monetary policy normalization outlined in its September 17, 2014 press release,[67] these actions do not result in a fundamental alteration to its accommodative monetary policy. Nor have they removed uncertainty over the trajectory of further interest rate increases or the overhanging implications of the Federal Reserve's enormous holdings of long-term securities.

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[66] In the aftermath of escalating tensions between the U.S. and North Korea during 2017, for example, Morningstar reported that, "U.S. Treasury prices rose on Tuesday, driving yields to their lowest levels since late 2016 as renewed market fears following a North Korean missile test stoked a flight into assets perceived as havens." Mark DeCambre and Anora Mahmudova, "Bond Report: 10-year Treasury Yields Fall Toward Post-election Lows As North Korea Tensions Rise," *MarketWatch*, Morningstar (Aug. 29, 2017).

[67] Press Release, Fed. Reserve, Policy Normalization Principles and Plans (Sept. 17, 2014), http://www.federalreserve.gov/newsevents/press/monetary/20140917c.htm.

The Federal Reserve continues to exert considerable influence over capital market conditions through its massive holdings of Treasuries and mortgage-backed securities. Prior to the initiation of the stimulus program in 2009, the Federal Reserve's holdings of U.S. Treasury bonds and notes amounted to approximately $400-$500 billion. With the implementation of its asset purchase program, balances of Treasury securities and mortgage backed instruments climbed steadily, and their effect on capital market conditions became more pronounced. Despite the Federal Reserve's gradual reductions in its balance sheet, which began in October 2017, its holdings of Treasury bonds and mortgage-backed securities continue to exceed $4.1 trillion.[68]

Considering the unprecedented magnitude of the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities, changes to the Federal Reserve's policy of reinvestment have significant, but unknown implications for investors.[69] A 2015 report from the global investment management firm BlackRock concluded that, "We are in uncharted territory," when it comes to the implications of unwinding the Federal Reserve's balance sheet holdings.[70] The Wall Street Journal observed the potential for "considerable upward pressure on long-term interest rates" if the need to finance higher deficits associated with stimulative fiscal policies coincides with a higher supply of Treasury securities as the Federal Reserve

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[68] *Factors Affecting Reserve Balances*, H.4.1 (Jun. 20, 2018). https://www.federalreserve.gov/releases/h41/current/.

[69] The Federal Reserve's holdings of Treasury bonds and mortgage-backed securities continue to exceed $4.1 trillion (*Factors Affecting Reserve Balances*, H.4.1, Jun. 20, 2018, https://www.federalreserve.gov/releases/h41/current/).

[70] BlackRock, "When the Fed Yields," *BlackRock Investment Institute* (May 2015).

unwinds its balance sheet holdings.[71] More recently, Zacks Investment Research ("Zacks") noted that "the rising interest rate environment could add to the woes of utility operators, as it will increase the cost of capital, restraining their ability to pay consistent dividends. . . . The Fed has increased the interest rate three times in the last three quarters, which will raise the cost of capital for the utilities."[72] The Wall Street Journal reported that:

> [M]arket moves suggest that investors are taking the prospect of a more hawkish Fed seriously, and that could affect investors across the market. Long-term yields may push higher as short-term rates rise and the Fed trims the size of its balance sheet. . . . Utilities stocks tend to get hurt by rising interest rates because they pay out high dividends that look less attractive relative to bonds when yields rise. S&P utilities stocks fell 0.9% over two sessions.[73]

Uncertainties over just how the process of normalizing the Federal Reserve's unprecedented monetary policies will affect capital markets further support the consideration of alternatives to DCF analyses and other ROE benchmarks when evaluating a just and reasonable ROE for UPPCO.

Q. Is there evidence that investors anticipate significantly higher interest rates in the foreseeable future?

A. Yes. Investors continue to anticipate that interest rates will increase significantly from present levels. With apprehension surrounding future Federal Reserve actions, uncertainties regarding the impact of TCJA and future fiscal policies, the potential for expanding federal deficits, and world-wide geopolitical exposures, the potential for significant volatility and higher capital costs is clearly evident to investors.

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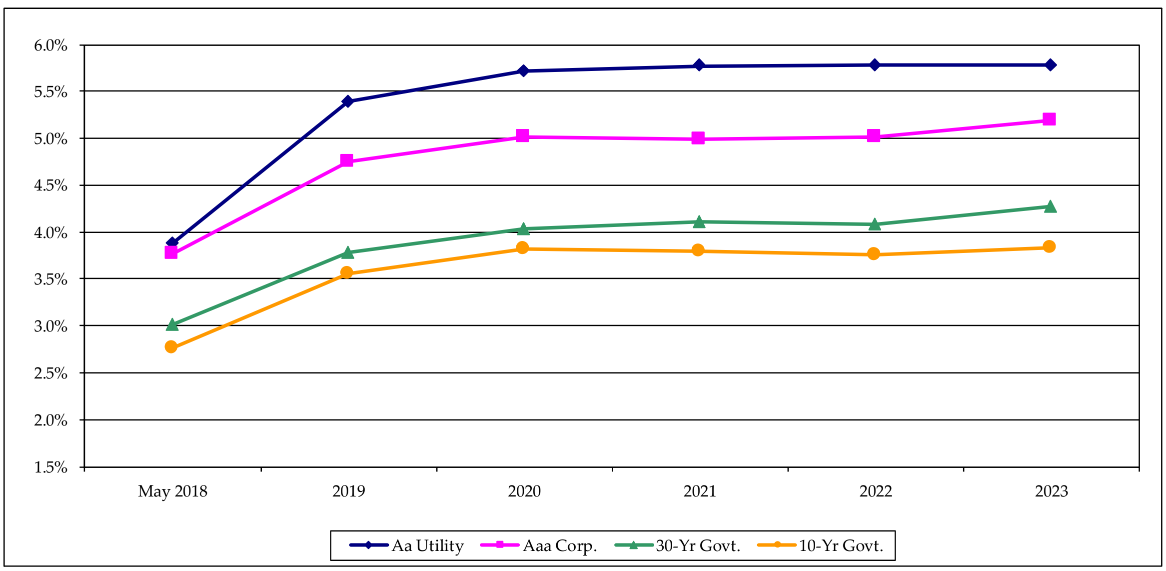
[71] Josh Zumbrun, "Trump's Fiscal Plans, Fed's Asset Unwinding Could Fuel Rate Rise," *The Outlook*, The Wall Street Journal (May 7, 2017).

[72] Mark Vickery, "Rising Interest Rates Make Life Tough for Utilities," Zacks Investment Research (Sep. 8, 2017).

[73] Ben Eisen, "Investors Appear Ready to Heed More Hawkish Fed," Wall Street Journal (Sep. 22, 2017).

For example, the June 1, 2018 long-term consensus forecast of economists published in the Blue Chip Financial Forecast ("Blue Chip") anticipates that corporate bond yields will increase approximately 150 basis points between 2018 and 2023.[74] Figure 1 below compares six-month average interest rates on 10-year and 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds as of May 2018 with the respective near-term projections from Value Line, IHS Global Insight, Blue Chip, and the Energy Information Administration ("EIA"), which are sources that are highly regarded and widely referenced:

FIGURE 1
INTEREST RATE TRENDS



Source:
Value Line Investment Survey, Forecast for the U.S. Economy (Jun. 1, 2018)
IHS Global Insight (Jun. 6, 2018)
Energy Information Administration, Annual Energy Outlook 2018 (Feb. 6, 2018)
Wolters Kluwer, Blue Chip Financial Forecasts, (Jun. 1, 2018)

[74] Wolters Kluwer, *Blue Chip Financial Forecast*, (Jun. 1, 2018).

As evidenced above, projections by investment advisors, forecasting services, and government agencies support the general consensus in the investment community that the present artificial low level of long-term interest rates will not be sustained.

Q. Does the fact that these projections have not yet materialized alter investors' general expectation that interest rates will rise substantially in the near-term?

A. No. The fact that past forecasts of higher interest rates have not come to fruition does not alter investors' general expectation that interest rates will rise substantially in the near-term future. While the actual pattern of bond yields may not track precisely with these near-term forecasts, they provide an objective, well-recognized guidepost to investors' future expectations. The cost of common equity to a regulated enterprise depends upon what the market expects, not upon what ultimately happens.

IV. UTILITY PROXY GROUP

Q. How did you implement quantitative methods to estimate the cost of common equity for UPPCO?

A. Application of quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices. 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 that inherently includes some degree of observation error. 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.

Q. What specific criteria did you initially examine to identify the proxy group?

A. In order to reflect the risks and prospects associated with UPPCO's jurisdictional utility operations, my analyses initially applied the following criteria to identify a proxy group of utilities:

1. Included in the Electric Utility Industry groups compiled by Value Line.
2. Triple-B corporate credit ratings from S&P (BBB-, BBB, and BBB+) and Moody's (Baa3, Baa2, and Baa1).
3. No ongoing involvement in a major merger or acquisition that would distort quantitative results.[75]
4. No cuts in dividend payments during the past six months and no announcement of a dividend cut since that time.

Q. Why did you use the lowest investment grade rating, triple-B, in evaluating your proxy group?

A. As noted earlier, the Company does not have its own bond ratings and UPPCO is rated below the investment grade category. Because there is only one publicly traded electric utility with below investment grade ratings (SCANA Corporation),[76] I restricted my proxy group to those electric utilities with triple-B credit ratings.

Q. What other publicly traded utility is relevant in evaluating a proxy group for UPPCO?

A. Although it has not yet been included in Value Line's electric utility industry groups, investors also regard Algonquin Power & Utilities, Inc. ("Algonquin") as having operations comparable to those of other electric utilities in the proxy group.

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[75] Avista Corp., CenterPoint Energy, Dominion Energy, Great Plains Energy, SCANA Corp., Vectren Corp., and Westar Energy were eliminated due to ongoing involvement in a major merger or acquisition.

[76] SCANA Corporation is involved in a merger and recently cut common dividend payments. Accordingly, this firm does not provide a sound basis on which to apply quantitative methods to estimate the cost of equity.

Algonquin is a North American diversified generation, transmission, and distribution utility with approximately $10 billion in total assets. Algonquin provides regulated utility services to over 782,000 customers in California, Iowa, Illinois, Missouri, Montana, Arkansas, Georgia, and Texas. Algonquin completed its acquisition of Empire District Electric Company ("Empire District") on January 1, 2017. Empire District was included in Value Line's electric utility industry group prior to its merger with Algonquin, and investors would regard Algonquin as a comparable investment alternative that is relevant to an evaluation of the required rate of return for UPPCO. While Algonquin is not rated by Moody's, it has been assigned a credit rating of BBB by S&P, which falls within the screening criterion identified above.

Q. Is there another publicly traded utility that is relevant in developing the Proxy Group?

A. In addition to the utilities meeting the criteria outlined above, Emera, Inc. ("Emera") should also be considered in evaluating investors' required rate of return for the Company. Emera's S&P and Moody's credit ratings fall within the comparable risk bands for the proxy group. The historical stock price and dividend data necessary to apply the DCF approach are available for the company, as are the consensus earnings per share ("EPS") growth rates from IBES and other comparable sources. Emera is also not engaged in any significant merger transactions that lead to distortion in the inputs to the DCF model.

Headquartered in Halifax, Nova Scotia, Canada, Emera is primarily engaged in electricity generation, transmission, and distribution; gas transmission and distribution; and utility energy services, and serves approximately 2.5 million customers. Emera completed its acquisition of TECO Energy on July 1, 2016.

While Emera is currently included in Value Line's "Power Industry" sector, Value Line also reported that as a result of the addition of TECO Energy's regulated utilities in Florida and New Mexico, "the percentage of profits coming from regulated businesses rises to more than 90%."[77]

Similarly, CFRA, founded as the Center for Financial Research and Analysis, highlighted Emera's primary focus on electric utility operations, and classified Emera in its "Electric Utilities" industry group,[78] and Emera reports as an "Electric Utility" under the Standard Industrial Classification Code (4911).[79] Thus, investors would regard Emera as a comparable investment alternative that is relevant to an evaluation of the required rate of return for UPPCO. Emera's operations are dominated by its U.S.-based utilities in Florida, Maine, and New Mexico, which together accounted for approximately 82% of consolidated net income in 2017.[80]

Applying the criteria outlined above results in a proxy group of seventeen utilities.

V. CAPITAL MARKET ESTIMATES

Q. What is the purpose of this section?

A. This section presents capital market estimates of the cost of equity. First, I address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe various quantitative

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[77] The Value Line Investment Survey (Mar. 24, 2017).

[78] CFRA, "Emera Incorporated," *Quantitative Stock Report* (Jun. 24, 2017). CFRA is one of the world's largest providers of institutional-grade independent equity research, acquired the equity and fund research arm of S&P in October 2016.

[79] *See, e.g.*, Emera, Inc., 2017 SEC Form 40-F. https://www.sec.gov/Archives/edgar/data/1127248/000119312518101807/d555438d40f.htm.

[80] Emera, Inc., 2017 SEC Form 40-F, Exhibit A-99.2 at 9.

analyses conducted to estimate the cost of common equity for the proxy group of comparable risk utilities.

A. Economic Standards

Q. What fundamental economic principle underlies the cost of equity concept?

A. 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 with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

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

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

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

Q. Is there evidence that the risk-return tradeoff principle actually operates in the capital markets?

A. 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.

Q. Does the risk-return tradeoff observed with fixed income securities extend to common stocks and other assets?

A. 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 directly observed. Yet there is every reason to believe that investors Exhibit A-risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. Is this risk-return tradeoff limited to differences between firms?

A. 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, common shareholders are the last in line and 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.

Q. What does the above discussion imply with respect to estimating the cost of common equity for a utility?

A. Although the cost of common equity cannot be observed directly, 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 cost of common equity 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

Q. How is the DCF model used to estimate the cost of common equity?

A. DCF models are based on the assumption that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[81]

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

where: P_0 = Current price per share;
D_1 = Expected dividend per share in the coming year;

[81] 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 of the above extend to infinity. Nevertheless, the DCF method provides a workable and practical approach to estimate investors' required return that is widely referenced in utility ratemaking.

k_e = 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.

Q. What steps are required to apply the constant growth DCF model?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (g) for the firm. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

Q. How did you determine the dividend yield for the Proxy Group?

A. 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 was then divided by a 30-day average stock price as of June 15, 2018 for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Proxy Group are presented on page 1 of Exhibit

A-60. As shown there, dividend yields for the firms in the Proxy Group ranged from 2.6% to 5.6%, and averaged 3.7%.

Q. What is the next step in applying the constant growth DCF model?

A. The next step is to evaluate 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.

Q. What are investors most likely to consider in developing their long-term growth expectations?

A. 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. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks and capital requirements in the industry, with the payout ratios falling significantly from historical levels. 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 are 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 dividends per share ("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 investors' future expectations.

Q. Do the growth rate projections of security analysts consider historical trends?

A. 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.

Q. Did Professor Myron J. Gordon, who originated the DCF approach, recognize the pivotal role that earnings play in forming investors' expectations?

A. 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."[82]

Q. Are analysts' assessments of growth rates appropriate for estimating investors' required return using the DCF model?

A. 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.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. 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 media and in investment advisory publications, as well as the continued success of services such as Thomson Reuters and 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

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

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>.[83]

Q. Have regulators also recognized that analysts' growth rate estimates are an important and meaningful guide to investors' expectations?

A. 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, especially given the current state of the economy.[84]

Similarly, FERC has expressed a clear preference for projected EPS growth rates in applying the DCF model to estimate the cost of equity for both electric and natural gas pipeline utilities:

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[83] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 298 (emphasis added).
[84] *Kentucky Utilities Co.*, Case No. 2009-00548 (Ky PSC Jul. 30, 2010) at 30-31.

> Opinion No. 414-A held that the IBES five-year growth forecasts for each company in the proxy group are the best available evidence of the short-term growth rates expected by the investment community. It cited evidence that (1) those forecasts are provided to IBES by professional security analysts, (2) IBES reports the forecast for each firm as a service to investors, and (3) the IBES reports are well known in the investment community and used by investors. The Commission has also rejected the suggestion that the IBES analysts are biased and stated that "in fact the analysts have a significant incentive to make their analyses as accurate as possible to meet the needs of their clients since those investors will not utilize brokerage firms whose analysts repeatedly overstate the growth potential of companies."[85]

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.[86]

Q. What are security analysts currently projecting in the way of growth for the firms in the Proxy Group?

A. The earnings growth projections for each of the firms in the Proxy Group reported by Value Line, IBES,[87] Zacks, Bloomberg, S&P Capital IQ, and FactSet are displayed on page 2 of Exhibit A-60.

Q. How else are investors' expectations of future long-term growth prospects often estimated when applying the constant growth DCF model?

A. 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

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[85] *Kern River Gas Transmission Co.*, 126 FERC ¶ 61,034at P 121 (2009) (footnote omitted).
[86] Public Utility Regulatory Authority of Connecticut, *Decision*, Docket No. 13-02-20 (Sept. 24, 2013).
[87] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters and presented at, for instance, https://finance.yahoo.com.

return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that 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 A-60, with the underlying details being presented on Exhibit A-61.[88]

Q. Are there significant shortcomings associated with the "br+sv" growth rate?

A. 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.[89]

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[88] Because Value Line reports end-of-year book values, an adjustment factor was incorporated to compute an average rate of return over the year, which is consistent with the theory underlying this approach.

[89] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 307.

The "sustainable growth" approach was 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.

Q. What cost of common equity estimates were implied for the Proxy Group using the DCF model?

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on page 3 of Exhibit A-60.

Q. In evaluating the results of the constant growth DCF model, is it appropriate to eliminate illogical low or high-end values?

A. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values 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.

Q. How did you evaluate DCF estimates at the low end of the range?

A. I based my evaluation of DCF estimates at the low end of the range on the fundamental risk-return tradeoff, which holds that investors will only take on more risk if they expect to earn a higher rate of return to compensate them for the greater uncertainly. Because common stocks lack the protections associated with an investment in long-term bonds, a utility's common stock imposes far greater risks on investors. As a result, the rate of return that investors require from a utility's common stock is considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, DCF results that are not sufficiently higher than the yield available on less risky utility bonds must be eliminated.

Q. Have similar tests been applied by regulators?

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold.[90] FERC affirmed that:

> The purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt. In public utility ROE cases, the Commission has used 100 basis points above the cost of debt as an approximation of this threshold, but has also considered the distribution of proxy group companies to inform its decision on which companies are outliers. As the Presiding Judge explained, this is a flexible test.[91]

Q. What interest rate benchmark did you consider in evaluating the DCF results for the Proxy Group?

A. Utility bonds rated "Baa" represent the lowest ratings grade for which Moody's publishes an index of average yields, and the closest available approximation for the risks of common stock, which are significantly greater than those of long-term debt. Monthly yields for Baa utility bonds reported by Moody's averaged 4.43% during the six-months ending May 2018.[92]

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[90] *See, e.g., Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 55 (2010).
[91] Opinion No. 531, 147 FERC ¶ 61,234 at P 122 (2014).
[92] Moody's Investors Service, *CreditTrends.*

Q. What else should be considered in evaluating DCF estimates at the low end of the range?

A. As indicated earlier, it is generally expected that long-term interest rates will rise as the Federal Reserve normalizes monetary policies. As shown in Table 3 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of 6.24% over the period 2019-2023:

TABLE 3
IMPLIED BAA BOND YIELD

	Baa Yield 2019-23
Projected Aa Utility Yield	
IHS Global Insight (a)	5.37%
EIA (b)	6.01%
Average	5.69%
Current Baa - Aa Yield Spread (c)	0.55%
Implied Baa Utility Yield	**6.24%**

(a) IHS Global Insight (Jun. 6, 2018).
(b) Energy Information Administration, Annual Energy Outlook 2018 (Feb. 6, 2018).
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Dec. 2017 - May 2018.

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely-referenced Blue Chip, which as noted earlier, projects that yields on corporate bonds will climb on the order of 150 basis points through 2023.

Q. What does this test of logic imply with respect to the DCF results for the Proxy Group?

A. Adding a 100 basis-point premium to the historical and projected average utility bond yields implies a threshold to evaluate the reasonableness of low-end values on the order of 5.4% to 7.2%. As highlighted on page 3 of Exhibit A-60, after considering this test and the distribution of individual estimates, I eliminated low-end DCF estimates ranging from -2.7% to 6.6%. 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, consistent with the threshold established by historical and projected utility bond yields, the values below the threshold provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q. What else should be considered in evaluating DCF estimates at the low end of the range?

A. While FERC has historically relied on a 100 basis point spread over public utility bond yields as a starting place in evaluating low-end values, reference to a static test ignores the implications of current low bond yields. Specifically, the premium that investors demand to bear the higher risks of common stock is not constant. As I demonstrate later in my testimony, equity risk premiums expand when interest rates fall, and vice versa. Given that bond yields have remained uncharacteristically low, this inverse relationship implies a significant increase in the equity risk premium that investors require to accept the higher uncertainties associated with an investment in utility common stocks versus bonds. As a result, using a fixed premium of 100 basis points over public utility bond yields will vastly understate the threshold for investors' minimum required return on utility stocks.

Q. Do you also recommend excluding estimates at the high end of the range of the DCF results?

A. While it is just as important to evaluate DCF estimates at the upper end of the range, there is no objective benchmark analogous to the bond yield averages used to eliminate illogical low-end values. In response, FERC has consistently applied a two-pronged test for high-end values based on the magnitude of the cost of equity estimate and its underlying growth rate. As FERC observed:

> The Presiding Judge found that the [utilities'] criteria for screening high-end outliers substantially complies with Commission precedent. . . The Presiding Judge further stated that the Commission's high-end outlier test since 2004 has been to exclude from the proxy group any company whose cost of equity estimate is at or above 17.7 percent and whose growth rate is at or above 13.3 percent.[93]

The upper end of the DCF results for the Proxy Group is set by a cost of equity estimates for Sempra Energy in the 30% range. This result exceeds the threshold tests employed by FERC and was eliminated. I eliminated four additional results that ranged from 17.8% to 22.4%. The remaining upper-end DCF value is set by estimates of 16.4%. While a 16.4% cost of equity estimate may exceed the majority of the remaining values, remaining low-end estimates in the 7.0% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the results, the remaining values provide a reasonable basis on which to frame the range of plausible DCF estimates and evaluate investors' required rate of return.

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[93] Opinion No. 531, 147 FERC ¶ 61,234 at P 115 (2014) (footnotes omitted).

q. What cost of common equity estimates are implied by your DCF results for the Proxy Group?

A. As shown on page 3 of Exhibit A-60 and summarized in Table 4 below, after eliminating illogical values, application of the constant growth DCF model resulted in the following average cost of common equity estimates:

TABLE 4
DCF RESULTS – PROXY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	10.3%	11.7%
IBES	10.2%	11.0%
Zacks	9.8%	10.0%
Bloomberg	9.7%	10.0%
S&P Capital/IQ	10.1%	11.0%
FactSet	9.7%	11.8%
br + sv	9.7%	11.8%

C. Capital Asset Pricing Model

Q. Please describe the Capital Asset Pricing Model.

A. 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 1.00, while stocks that tend to move more than the market have betas greater than 1.00. 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, in order 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.

Q. Why is the CAPM approach a relevant component when evaluating the cost of equity for UPPCO?

A. 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 UPPCO.

Q. How did you apply the CAPM to estimate the cost of common equity?

A. Application of the CAPM to the Proxy Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit A-62. In order 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 was obtained from Zacks, and the growth rate was equal to the average of the earnings growth projections for each firm published by Value Line, IBES and Zacks, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the individual firms, current estimates imply an average growth rate over the next five years of 11.1%. Combining this average growth rate with a year-ahead dividend yield of 2.4% results in a current cost of common equity estimate for the market as a whole (R_m) of 13.5%. Subtracting a 3.0% risk-free rate based on the average yield on 30-year Treasury bonds for the six-months ending May 2018 produced a market equity risk premium of 10.5%.

Q. What was the source of the beta values you used to apply the CAPM?

A. 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.

Q. What else should be considered in applying the CAPM?

A. 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.[94]

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.[95] Accordingly, my CAPM analyses also incorporated an adjustment to recognize the impact of size distinctions, as measured by the market capitalization for the firms in the Proxy Group.

Q. Does this size adjustment mean that you are incorporating an explicit premium to the ROE because of UPPCO's relative size?

A. No. I am not proposing to apply an explicit size risk premium in evaluating a fair and reasonable ROE for UPPCO. Rather, the size adjustment is tied to the CAPM and merely corrects for an observed inability of the beta measure to fully reflect the risks perceived by investors for the firms in the Proxy Group. As FERC has recognized, "This type of size adjustment is a generally accepted approach to CAPM analyses."[96]

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[94] *Morningstar*, "Ibbotson SBBI 2015 Classic Yearbook," at 99, 108.
[95] Originally compiled by Ibbotson Associates and published in their annual yearbook entitled, "Stocks, Bonds, Bills and Inflation," these size premia are now developed by Duff & Phelps and presented in its "Valuation Handbook – Guide to Cost of Capital."
[96] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 117 (2015).

Q. What is the implied ROE for the Proxy Group using the CAPM approach?

A. As shown on page 1 of Exhibit A-62, after adjusting for the impact of firm size the CAPM approach implied an average cost of equity estimate of 11.0% and a midpoint estimate of 10.8% for the Proxy Group.

Q. Did you also apply the CAPM using forecasted bond yields?

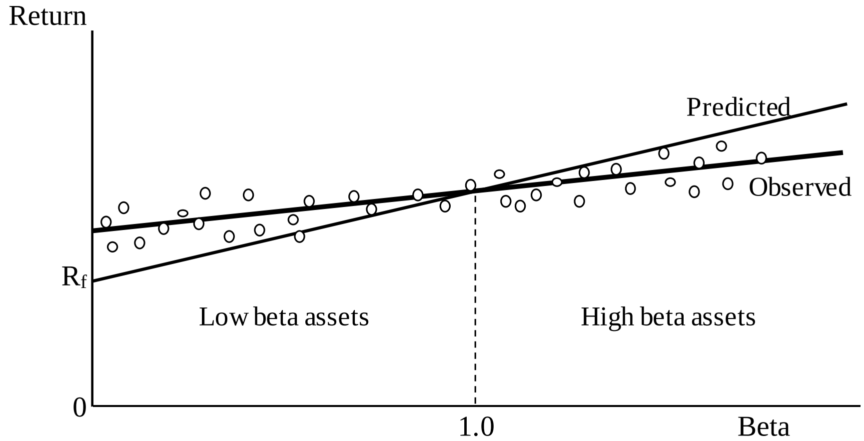
A. Yes. As discussed earlier, there is general consensus that interest rates will increase materially as the Federal Reserve normalizes its monetary policies going forward. Accordingly, in addition to the use of current bond yields, I applied the CAPM based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight, and Blue Chip. As shown on page 2 of Exhibit A-62, incorporating a forecasted Treasury bond yield for 2019-2023 implied an average and midpoint cost of equity estimate of 11.2% for the Proxy Group after adjusting for the impact of relative size.

D. Empirical Capital Asset Pricing Model

Q. How does the ECAPM approach differ from traditional applications of the CAPM?

A. 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 returns than predicted by the CAPM. This is illustrated graphically in the figure below:

FIGURE 2
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.[97]

As discussed in *New Regulatory Finance*, 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:

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

[97] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports* (2006) at 189.

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 stocks relative volatility [(β)(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.

Q. Is the use of the ECAPM consistent with the use of value line betas?

A. Yes. Value Line beta values are adjusted for the observed tendency of beta to converge toward the mean value of 1.00 over time.[98] 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 2 is flatter than predicted by the CAPM. In other words, even if a firm's beta value were estimated with perfect precision, the 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.

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[98] *See, e.g.*, Marshall E. Blume, "Betas and Their Regression Tendencies," *Journal of Finance*, Vo. 30, No. 3 (Jun. 1975) at 785-795.

Q. Have other regulators relied on the ECAPM?

A. Yes. The ECAPM approach has been relied on by the Staff of the Maryland Public Service Commission. For example, Staff witness Julie McKenna noted that "the ECAPM model adjusts for the tendency of the CAPM model to underestimate returns for low Beta stocks," and concluded that, "I believe under current economic conditions that the ECAPM gives a more realistic measure of the ROE than the CAPM model does."[99] The Regulatory Commission of Alaska has also relied on the ECAPM approach, noting that:

> 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 investor would be aware of these empirical results. Therefore, we adjust Tesoro's recommendation to reflect only the ECAPM result.[100]

The staff of the Colorado Public Utilities Commission has also recognized that, "The ECAPM is an empirical method that attempts to enhance the CAPM analysis by flattening the risk-return relationship,"[101] and relied on the exact same standard ECAPM equation presented above.[102] The Wyoming Office of Consumer Advocate, an independent division of the Wyoming Public Service Commission, has also relied on this same ECAPM formula in estimating the cost of equity for a natural gas utility, as have witnesses for the Office of Arkansas Attorney General.[103]

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[99] *Direct Testimony and Exhibit A-s of Julie McKenna,* Maryland PSC Case No. 9299 (Oct. 12, 2012) at 9.
[100] Regulatory Commission of Alaska, Order No. P-97-004(151) (Nov. 27, 2002) at 145.
[101] Proceeding No. 13AL-0067G, *Answer Testimony and Exhibit A-s of Scott England* (July 31, 2013) at 47.
[102] *Id.* at 48.
[103] Docket No. 30011-97-GR-17, *Pre-Filed Direct Testimony of Anthony J. Ornelas* (May 1, 2018) at 52-53; Docket No. 17-071-U, *Direct Testimony of Marlon F. Griffing, PH.D.* (May 29, 2018) at 33-35.

Q. What cost of equity estimates were indicated by the ECAPM?

A. My applications of the ECAPM were based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connection with the CAPM. As shown on page 1 of Exhibit A-63, applying the forward-looking ECAPM approach to the firms in the Proxy Group results in an average cost of equity estimate of 11.8% after incorporating the size adjustment corresponding to the market capitalization of the individual utilities. The midpoint of the size adjusted ECAPM range is 11.7%.

As shown on page 2 of Exhibit A-63, incorporating a forecasted Treasury bond yield for 2019-2023 implied an average and midpoint cost of equity for the Proxy Group of 12.0%, after adjusting for the impact of relative size.

E. Utility Risk Premium

Q. Briefly describe the risk premium method.

A. The risk premium method extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. Is the risk premium approach a widely accepted method for estimating the cost of equity?

A. 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 in order 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 fair and reasonable ROE for UPPCO.

Q. How did you implement the risk premium method?

A. Estimates of equity risk premiums for utilities were 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.

Q. Is it circular to consider risk premiums based on authorized returns in assessing a fair and reasonable ROE for UPPCO?

A. No. In establishing authorized ROEs, regulators typically consider the results of alternative market-based approaches, including the DCF model. 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.

Q. How did you calculate the equity risk premiums based on allowed ROEs?

A. The ROEs authorized for electric utilities by regulatory commissions across the U.S. are compiled by RRA and published in its *Regulatory Focus* report. In Exhibit A-64, 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 2017.[104] As shown on page 3 of Exhibit A-64, over this period, these equity risk premiums for electric utilities averaged 3.71%, and the yield on public utility bonds averaged 8.28%.

Q. Is there any capital market relationship that must be considered when implementing the risk premium method?

A. 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.

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

Q. Has this inverse relationship been documented in the financial research?

A. 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.[105] As summarized by *New Regulatory Finance*:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carelton, 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.[106]

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 lock-step.[107] This relationship is illustrated in the figure on page 4 of Exhibit A-64.

Q. What cost of equity is implied by the risk premium method using surveys of allowed ROEs?

A. Based on the regression output between the interest rates and equity risk premiums displayed on page 4 of Exhibit A-64, the equity risk premium for electric utilities increased (decreased) approximately 43 basis points for each percentage point decrease (increase) in the yield on average public utility bonds. As illustrated on page 1 of Exhibit A-64, with an average yield on public utility bonds for the six-months ending May 2018 of 4.12%, this implied a current equity risk premium of

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[105] *See, e.g.,* E. F. Brigham, D. K. Shome, and S. R. Vinson, "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management* (Spring 1985); R. S. Harris and F. C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management* (Summer 1992).

[106] Roger A. Morin, "New Regulatory Finance," Public Utilities Reports (2006) at 128.

[107] *See, e.g.*, California Public Utilities Commission, Decision 08-05-035 (May 29, 2008); Entergy Mississippi Formula Rate Plan FRP-5, http://www.entergy-mississippi.com/content/price/tariffs/emi_frp.pdf; *Martha Coakley et al.*, 147 FERC ¶ 61,234 at P 147 (2014).

5.51% for electric utilities. Adding this equity risk premium to the average yield on triple-B utility bonds of 4.43% implies a current cost of equity of 9.94%.

Q. What risk premium cost of equity estimate was produced after incorporating forecasted bond yields?

A. As shown on page 2 of Exhibit A-64, incorporating a forecasted yield for 2019-2023 and adjusting for changes in interest rates since the study period implied an equity risk premium of 4.72% 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 triple-B public utility bonds for 2019-2023 of 6.24% resulted in an implied cost of equity of 10.96%.

F. Expected Earnings Approach

Q. What other analyses did you conduct to estimate the cost of common equity?

A. As I noted earlier, I also evaluated the cost of common equity 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 fair and reasonable rate of return established by the U.S. Supreme Court in *Bluefield* and *Hope*. Moreover, it avoids the complexities and limitations of capital market methods, such as the DCF and CAPM methodologies, and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. What economic premise underlies the expected earnings approach?

A. 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. Such an outcome would violate the *Hope* and *Bluefield* standards and undermine the utility's access to capital on reasonable terms.

Q. How is the expected earnings approach typically implemented?

A. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Moreover, regulators do not set the returns that investors earn in the capital markets, which are a function of dividend payments and fluctuations in common stock prices – both of which are outside their control. Regulators can only establish the allowed ROE, which is applied to the book value of a utility's investment in rate base, as determined from its accounting records. This is directly 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.

Q. What rates of return on equity are indicated for UPPCO based on the expected earnings approach?

A. Value Line's projections imply an average rate of return on common equity for the electric utility industry of 10.7% over its 2021-2023 forecast horizon.[108] Meanwhile, for the firms in the Proxy Group specifically, the year-end returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit A-65. 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.[109] Accordingly, these year-end values were converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit A-61. As shown on Exhibit A-65, after excluding values at the bottom and top of the

[108] The Value Line Investment Survey (Feb. 16, Mar. 16, & Apr. 27, 2018 and Mar. 23, 2018 for Emera). Recall that Value Line reports return on year-end equity so the equivalent return on average equity would be higher.

[109] 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.

range, Value Line's projections for the Proxy Group suggest an average ROE of approximately 10.9%, with a midpoint value of 11.6%.

VI. NON-UTILITY BENCHMARK

Q. What is the purpose of this section of your testimony?

A. 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 directly considered in arriving at my recommended ROE range of reasonableness; however, it is my opinion that this is a relevant consideration in evaluating a fair and reasonable ROE for the Company.

Q. Do utilities have to compete with non-regulated firms for capital?

A. 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 are 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.

Q. Is it consistent with the *Bluefield* and *Hope* cases to consider investors' required ROE for non-utility companies?

A. Yes. The cost of equity capital in the competitive sector of the economy form 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.[110]

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

Q. Does consideration of the results for the Non-Utility Group help to improve the reliability of DCF results?

A. 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. The result of such distortions would be to bias the 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.

Q. What criteria did you apply to develop the Non-Utility Group?

A. My low-risk group of competitive firms 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.

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

4. Have a beta of 0.75 or less.
5. Have investment grade credit ratings from S&P and Moody's.

Q. How do the overall risks of this Non-Utility Group compare with the Utility Group?

A. Table 5 compares the Non-Utility Group with the Utility Group across five measures of investment risk:

TABLE 5
COMPARISON OF RISK INDICATORS

	Credit Rating		Value Line		
	S&P	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Non-Utility Group	A-	A3	1	A+	0.73
Utility Group	BBB	Baa2	2	B++	0.69

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 and 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, Value Line's beta measures the volatility of a security's price relative to the market as a whole. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. Beta is the only relevant measure of investment risk under modern capital market theory and is cited widely in academia and in the investment industry as a guide to investors' risk perceptions.

As the table shows, the average risk indicators for the Non-Utility Group suggest less risk than for the proxy group of electric utilities. 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 Utility Group are greater than those of the firms in the Non-Utility Group.

The companies that make up the Non-Utility Group are representative of the pinnacle of corporate America. These firms, which include household names such as Coca-Cola, Procter & Gamble, and Walmart, have long corporate histories, well-established track records, and exceedingly conservative risk profiles. Many of these companies pay dividends on a par with utilities, with the average dividend yield for the group of 3.4%.[111] 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.

[111] Exhibit A-66, page 1.

Q. What were the results of your DCF analysis for the Non-Utility Group?

A. I applied the DCF model to the Non-Utility Group using analysts' EPS growth projections, as described earlier for the Utility Group, with the results being presented in Exhibit A-66. As summarized in Table 6 below, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE 6
DCF RESULTS – NON-UTILITY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	11.3%	12.1%
IBES	11.3%	12.5%
Zacks	11.2%	11.7%
Bloomberg	11.2%	10.8%
S&P Capital/IQ	11.9%	12.7%
FactSet	11.7%	10.8%

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 fair and reasonable ROE for UPPCO.

VII. CONCLUSIONS AND RECOMMENDATIONS

Q. What is your conclusion regarding the 10.5% ROE requested by UPPCO?

A. As discussed in Section V of my testimony, and as summarized in Exhibit A-57, I applied alternative quantitative analyses to estimate the cost of equity for a proxy group of other electric utilities. Given those analyses, and the assessment of

UPPCO's relative risks discussed in Section II, it is my conclusion that the 10.5% ROE requested by UPPCO is just and reasonable. Specifically, as indicated by the evidence presented in my testimony:

- Considering the results of my alternative analyses, and giving less weight to extremes at the high and low ends of the range, I concluded that the cost of equity for the proxy group of utilities is in the 9.8% to 10.8% range.
- In contrast to the large, publicly traded that make up the Proxy Group, UPPCO faces significantly greater risks related to its small size, sizable construction program, economically vulnerable service area, lack of efficient regulatory mechanisms and published risk measures, inability to earn its allowed return, and potentially volatile power supply mix.
- When considered along with the imperative of ensuring that UPPCO has the financial flexibility necessary to meet the long-term energy needs of its service area, these higher risks support the reasonableness of the 10.5% ROE requested by UPPCO, which falls well within the upper end of my recommended range for the Proxy Group.

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

A. Yes.

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.

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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-20276

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)

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City Lansing State MI

Zip 48933 Phone (517) 483-4954

Email collinsp@millercanfield.com

Date September 21, 2018

Signature: Paul Collins Digitally signed by: Paul Collins DN: CN = Paul Collins email = collinsp@millercanfield.com C = US Date: 2018.09.21 09:50:56 -04'00'

☐ I am not an attorney

☑ I am an attorney whose:

Michigan Bar # is P-69719

_____________Bar # is: _____________
(state)

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Please enter my appearance in the above-entitled matter on behalf of:

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2. (Name)
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4. (Name)
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Date September 21, 2018

Signature: Sherri A. Wellman Digitally signed by: Sherri A. Wellman DN: CN = Sherri A. Wellman email = wellmans@millercanfield.com C = US Date: 2018.09.21 09:50:25 -04'00'

☐ I am not an attorney

☑ I am an attorney whose:

Michigan Bar # is P-38989

____________ Bar # is: ____________
(state)

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MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

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Case / Company Name: Upper Peninsula Power Company Docket No. U-20276

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Upper Peninsula Power Company
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4. (Name)
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Date September 21, 2018

Signature: Matthew Carstens Digitally signed by: Matthew Carstens DN: CN = Matthew Carstens email = carstens@millercanfield.com C = US O = Miller Canfield Date: 2018.09.21 09:51:45 -04'00'

☐ I am not an attorney

☑ I am an attorney whose:

Michigan Bar # is P-61070

_____________ Bar # is: _____________
(state)

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EAHR1 - 09/29/2016

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** for authority to increase retail electric rates.	))))	Case No. U-20276

PROOF OF SERVICE

Kimberly S. Fox, being first duly sworn, deposes and says that on September 21, 2018 she served the documents listed below upon the parties listed on the attached Service List via United States Mail, with first class postage fully prepaid.

(1) Application;
(2) Notice of Hearing;
(3) Affidavit of Gradon R. Haehnel;
(4) Direct Testimony of James C. Larsen;
(5) Direct Testimony and Exhibits of Nicholas E. Kates, Gradon R. Haehnel, Eric W. Stocking, Keith E. Moyle, Jason Brynick, and Adrien M. McKenzie;
(6) Documentation which complies with Part II of the Rate Case Filing Requirements established by the Commission's order dated July 31, 2017, issued in Case No. U-18238;
(7) Protective Order; and
(8) Appearances of Sherri A. Wellman, Paul M. Collins, Matthew S. Carstens.

Kimberly S. Fox
Digitally signed by: Kimberly S. Fox
DN: CN = Kimberly S. Fox email = fox@millercanfield.com C = US O = Miller Canfield PLC
Date: 2018.09.21 11:47:02 -04'00'

Kimberly S. Fox

Subscribed and sworn before me
on this 21st day of September, 2018.

Jennifer Joy Yocum
Digitally signed by: Jennifer Joy Yocum
DN: CN = Jennifer Joy Yocum C = US
Date: 2018.09.21 11:47:21 -04'00'

Jennifer Joy Yocum, Notary Public
State of Michigan, Ingham County
My Commission Expires: December 17, 2018
Acting in Ingham County

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