February 21, 2019

Ms. Kavita Kale
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48917

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

Dear Ms. Kale:

Please find enclosed the Direct Testimony and Exhibits of Douglas B. Jester, prepared on behalf of the Citizens Against Rate Excess in the above entitled matter, and a Certificate of Service.

Please do not hesitate to contact me if you have any questions.

Very truly yours,

[Signature]

Digitally signed by John R. Liskey
Date: 2019.02.21 09:39:35 -05'00'

John R Liskey (P31580)

Enclosure
cc: All parties of Interest
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
________________________________________

Certificate of Service

John R Liskey certifies that on the 21st day of February, 2019, he served a copy of the Direct Testimony and Exhibits of Douglas B. Jester, filed with the Commission on behalf of the Citizens Against Rate Excess in the above-captioned matter, on all of the parties of the case via the respective email addresses shown on the Service List below.

John R Liskey
Upper Peninsula Power Company  
Case No. U-20276  
Service List

**Administrative Law Judge**  
Hon. Martin D. Snider  
Administrative Law Judge  
Michigan Public Service Comm.  
7109 W. Saginaw Hwy., 3rd Floor  
Lansing, MI 48917  
sniderm@michigan.gov

**Counsel for Upper Peninsula Power Company**  
Sherri A. Wellman  
Paul M. Collins  
Matthew Carstens  
Miller Canfield Paddock & Stone P.L.C.  
One Michigan Ave, Suite 900  
Lansing, MI 48933  
wellmans@millercanfield.com  
collinsp@millercanfield.com  
carstens@millercanfield.com

**Counsel for Michigan Public Service Commission Staff**  
Amit T. Singh  
Heather Durian  
Daniel E. Sonneveldt  
Emily A. Jefferson  
Assistant Attorneys General  
Michigan Public Service Commission  
7109 W. Saginaw Hwy., 3rd floor  
Lansing, MI 48917  
singha9@michigan.gov  
durianh@michigan.gov  
sonneveltdt@michigan.gov  
jeffersonel@michigan.gov

**Counsel for Verso Corporation**  
Timothy J. Lundgren  
Varnum LLP  
201 N. Washington Square, Suite 910  
Lansing, MI 48933  
tjlundgren@varnumlaw.com

Justin K. Ooms
Counsel for Calumet Electronics Corporation
Michael J. Brown
Carlin Edwards Brown PLLC
6017 W. St. Joe Highway, Suite 202
Lansing, MI 48917
MBrown@cebhlaw.com

Counsel for Association of Businesses Advocating Tariff Equity (ABATE)
Sean P. Gallagher
Stephen A. Campbell
Clark Hill PLC
212 East César E. Chávez Avenue
Lansing, MI 48906
517-318-3100
sgallagher@clarkhill.com
scampbell@clarkhill.com

Consultant for ABATE
James Dauphinais
Amanda Alderson Brubaker & Associates, Inc.
16690 Swingley Ridge Rd., Suite 140
Chesterfield, Missouri 63017
jdauphinais@consultbai.com
aalderson@consultbai.com

Counsel for Energy Michigan
Laura A. Chappelle
201 N. Washington Square
Lansing, MI 48933
lachappelle@varnumlaw.com

Office of the Attorney General
Michael E. Moody
Division Chief
Special Litigation Division
P. O. Box 30755
Lansing, MI 48909
MoodyM2@michigan.gov
ag-enra-spec-lit@michigan.gov
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
Douglas B. Jester

On behalf of
Citizens Against Rate Excess

February 21, 2019
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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state for the record your name, position, and business address.
A. My name is Douglas B. Jester. I am a Partner of 5 Lakes Energy LLC, a Michigan limited liability corporation, located at Suite 710, 115 W Allegan Street, Lansing, Michigan 48933.

Q. On whose behalf is this testimony being offered?
A. I am testifying on behalf of Citizens Against Rate Excess (“CARE”).

Q. Please summarize your experience in the field of electric utility regulation.
A. I have worked for more than 20 years in electricity industry regulation and related fields. My work experience is summarized in my resume, provided as Attachment A.

Q. Have you testified before this Commission or as an expert in any other proceeding?
A. I have previously testified before the Michigan Public Service Commission in the following cases:

  • Case U-17473 (Consumers Energy Plant Retirement Securitization);
  • Case U-17096-R (Indiana Michigan 2013 PSCR Reconciliation);
  • Case U-17301 (Consumers Energy Renewable Energy Plan 2013 Biennial Review);
  • Case U-17302 (DTE Energy Renewable Energy Plan 2013 Biennial Review);
  • Case U-17317 (Consumers Energy 2014 PSCR Plan);
  • Case U-17319 (DTE Electric 2014 PSCR Plan);
  • Case U-17671-R (UPPCO 2015 PSCR Reconciliation);
  • Case U-17674 (WEPCO 2015 PSCR Plan);
  • Case U-17674-R (WEPCO 2015 PSCR Reconciliation);
• Case U-17679 (Indiana-Michigan 2015 PSCR Plan);
• Case U-17688 (Consumers Energy Cost of Service and Rate Design);
• Case U-17689 (DTE Electric Cost of Service and Rate Design);
• Case U-17698 (Indiana-Michigan Cost of Service and Rate Design);
• Case U-17735 (Consumers Energy General Rates);
• Case U-17752 (Consumers Energy Community Solar);
• Case U-17762 (DTE Electric Energy Optimization Plan);
• Case U-17767 (DTE General Rates);
• Case U-17792 (Consumers Energy Renewable Energy Plan Revision);
• Case U-17895 (UPPCO General Rates);
• Case U-17911 (UPPCO 2016 PSCR Plan);
• Case U-17911-R (UPPCO 2016 PSCR Reconciliation);
• Case U-17990 (Consumers Energy General Rates);
• Case U-18014 (DTE General Rates);
• Case U-18089 (Alpena Power PURPA Avoided Costs);
• Case U-18090 (Consumers Energy PURPA Avoided Costs);
• Case U-17911-R (UPPCO 2016 PSCR Reconciliation);
• Case U-18091 (DTE PURPA Avoided Costs);
• Case U-18092 (Indiana Michigan Power Company PURPA Avoided Costs);
• Case U-18093 (Northern States Power PURPA Avoided Costs);
• Case U-18094 (Upper Peninsula Power Company PURPA Avoided Costs);
• Case U-18095 (Wisconsin Public Service Company PURPA Avoided Costs);
• Case U-18096 (Wisconsin Electric Power Company PURPA Avoided Costs);
• Case U-18224 (UMERC Certificate of Necessity);
• Case U-18255 (DTE Electric General Rates);
• Case U-18322 (Consumers Energy General Rates);
• Case U-18406 (UPPCO 2018 PSCR Plan);
• Case U-18408 (UMERC 2018 PSCR Plan);
• Case U-18419 (DTE Certificate of Necessity);
• Case U-20111 (UPPCO TCJA Adjustment);
• Case U-20134 (Consumers Energy General Rates);
• Case U-20150 (UPPCO RDM Complaint);
• Case U-20162 (DTE Electric General Rates);
• Case U-20134 (Consumers Energy IRP); and
• Case U-20229 (UPPCO PSCR Plan).

Additionally, I have testified as an expert witness before the Public Utilities Commission of Nevada in Case No. 16-07001 concerning the 2017-2036 integrated resource plan of NV Energy; and before the Missouri Public Service Commission in Cases Nos. ER-2016-0179, ER-2016-0285, and ET-2016-0246 concerning residential rate design and electric vehicle (“EV”) policy, revenue requirements, cost of service, and rate design. I testified before the Kentucky Public Service Commission in Case No. 2016-00370 concerning municipal street lighting rates and technologies, and the Massachusetts Department of Public Utilities in Case Nos. DPU 17-05 and DPU 17-13 concerning EV charging infrastructure program design and cost recovery.
I have also testified as an expert witness on behalf of the State of Michigan before the Federal Energy Regulatory Commission in cases relating to the relicensing of hydro-electric generation, and have participated in state and federal court cases on behalf of the State of Michigan, concerning electricity generation matters, which were settled before trial.

6 Q. What is the purpose of your testimony?

7 A. I will:

8 (1) draw the Commission’s attention to the importance of rate of return and credits related to the 2014 sale of UPPCO in determining the amount of revenue UPPCO is requesting in this case;

9 (2) establish a basis for the Commission to consider UPPCO’s performance in establishing its authorized rate of return;

10 (3) argue that UPPCO’s proposed adjustment to certain revenue credits is inappropriate retroactive ratemaking and unfair in its effects on various rate classes;

11 (4) show that the allocation of production plant costs in the Company’s cost of service study is incorrect;

12 (5) show that UPPCO’s proposed use of revenue credits to mitigate changes in revenue responsibility between classes is inconsistent with the basis for those credits and is thus unfair and unjust;

13 (6) show that UPPCO’s proposal to increase monthly fixed charges is contrary to the Commission’s precedents on this topic and unfair to certain customers;

14 (7) provide analysis and propose an alternative to UPPCO’s proposal for a distributed generation tariff.
Q. Are you sponsoring any exhibits?

A. Yes. I have attached the following exhibits for review.

- CARE-1: Comparative Performance of Michigan Utilities
- CARE-2: UPPCO Response to 1-CARE-UPPCO-010
- CARE-3: MISO 2018-19 Cost of New Entry
- CARE-4: Revenue Responsibility with 20:80 Production Plant Allocator
- CARE-5: UPPCO COSS Revenue Responsibility vs Rate Design Revenue
- CARE-6: CARE’s Proposed Revenue Credit Allocation
- CARE-7: CARE’s Proposed Revenue Responsibility for UPPCO’s Revenue Requirement
- CARE-8: UPPCO Response to 1-CARE-UPPCO-001

II. BACKGROUND AND CONTEXT

Q. Please summarize the major elements of this case from your perspective.

A. In this case, the Company requests rate adjustments based on a projected test year consisting of January 1, 2019 through December 31, 2019.

The Company claims that it proposes $9.98 million incremental jurisdictional revenue in the future test year compared to the base rates now in effect. The following table illustrates the factors determining the Company’s proposal by comparing jurisdictional information for 2017 from “Revenue Deficiency (Sufficiency)” in Exhibit A-1, Schedule A1, with jurisdictional information for the future test year from the “Revenue Deficiency (Sufficiency)” in Exhibit A-11, Schedule A1 and a comparable calculation without the
increase in return on equity and reduction of revenue credits proposed by the Company.

<table>
<thead>
<tr>
<th>Description</th>
<th>Calendar Year 2017</th>
<th>Full Rate Relief</th>
<th>No ROE Increase/Revenue Credit Adjustment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rate Base</td>
<td>$251,943,359</td>
<td>$278,888,974</td>
<td>$278,888,974</td>
</tr>
<tr>
<td>Adjusted Net Operating Income (based on current rates)</td>
<td>$12,453,338</td>
<td>$11,262,295</td>
<td>$11,262,295</td>
</tr>
<tr>
<td>Overall Rate of Return</td>
<td>4.94%</td>
<td>4.04%</td>
<td>4.04%</td>
</tr>
<tr>
<td>Required Rate of Return</td>
<td>6.93%</td>
<td>7.57%</td>
<td>6.93%</td>
</tr>
<tr>
<td>Income Required</td>
<td>$17,468,997</td>
<td>$21,110,780</td>
<td>$19,327,006</td>
</tr>
<tr>
<td>Income Deficiency/ (Sufficiency)</td>
<td>$5,015,549</td>
<td>$9,848,484</td>
<td>$8,064,711</td>
</tr>
<tr>
<td>Revenue Multiplier</td>
<td>1.6367</td>
<td>1.3466</td>
<td>1.3466</td>
</tr>
<tr>
<td>Revenue Deficiency/ (Sufficiency)</td>
<td>$8,208,948</td>
<td>$13,261,969</td>
<td>$10,859,940</td>
</tr>
<tr>
<td>Revenue Credit U-17564</td>
<td>($4,333,333)</td>
<td>($2,584,802)</td>
<td>($4,333,333)</td>
</tr>
<tr>
<td>Defer Pension &amp; Transition Costs</td>
<td>($390,000)</td>
<td>($694,563)</td>
<td>($694,563)</td>
</tr>
<tr>
<td>Revenue Deficiency</td>
<td>$3,485,615</td>
<td>$9,982,604</td>
<td>$5,832,044</td>
</tr>
</tbody>
</table>

Thus, the Company claims that it had a revenue deficiency in the 2017 historical test year of $3.486 million, projects a deterioration of $1.19 million in net operating income, seeks an increase in rate of return that requires an additional $1.78 million in income or $2.40 million in revenue, proposes to reduce revenue credits related to case U-17564 by $1.75 million, and recognizes an increase in deferred pension and transition costs of about $0.3 million. Thus, the Company’s request for $9.98 million in increased revenue consists of $5.83 million to bolster net operating income and achieve the currently authorized rate of return and $4.15 million in proposed authorization to improve the Company’s financial
performance above that authorized in the last case.

It should also be noted that this revenue deficiency is smaller than it would otherwise be, by virtue of the lower corporate income tax rate established in the 2017 Tax Cuts and Jobs Act. If the revenue multiplier continued to be 1.6367 rather than being reduced to 1.3466, the revenue increase required to achieve the Company’s currently authorized rate of return would be an additional $2.34 million.

Q. Did you evaluate the UPPCO’s claim as to its revenue deficiency?
A. No, aside from my observation that a significant portion of the claimed deficiency is related to their proposal to increase rate of return and to reduce revenue credits. My testimony is otherwise focused on cost of service allocation and rate design.

III. PERFORMANCE, INCENTIVES, AND RETURN ON EQUITY

Q. What other matters should the Commission consider in deciding this case?
A. On April 20, 2018, the Commission submitted a “Report on the Study of Performance-Based Regulation” (“PBR Report”) to the legislature and governor pursuant to Section 6u of 2016 PA 341.¹ The PBR Report is complete, and no further consideration is required by law. However, the PBR Report contains recommendations that the Commission can implement without changes in law. Since the PBR Report was formally submitted relatively close to the Company’s application in the present case, it is unsurprising that the Company’s filings in this case do not refer to that Report. Nonetheless, to the extent the Commission recommends a course of action authorized by law, it is appropriate for the

¹ See https://www.michigan.gov/mpsc/0,4639,7-159-80741_80743-406274--,00.html (last visited November 7, 2018) for a copy of the Report and Appendices.
Commission to consider its own recommendations concerning performance-based regulation.

Q. **How do you recommend that the Commission evaluate UPPCO’s performance?**

A. I recommend that the Commission consider the Company’s comparative performance on broad criteria when determining the Company’s authorized return on equity and any executive or employee incentive compensation plans.

Q. **How should the Commission consider the Company’s comparative performance on broad criteria in authorizing return on equity in the present case?**

A. The Commission should consider comparative performance using nationally comprehensive statistics in setting authorized return on equity. Doing so will potentially serve three purposes:

- More accurately simulating market discipline in the regulatory process and thereby better reflecting the purpose of monopoly regulation;
- Incentivizing improved performance by the Company;
- Fairer treatment of UPPCO’s customers vis-à-vis the customers of other utilities.

The basic logic of considering performance in authorizing return on equity is most easily understood in the context of FERC’s discounted cash flow method for determining return on equity. That methodology is based on the common understanding in corporate finance that the basic valuation of a Company is based on its discounted expected returns to owners,

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2 The current method for applying the DCF method to electric utilities was adopted by FERC in Order 531 within Docket No. EL 11-66-001.
which ultimately consist of dividends or equity buy-backs (though intermediate returns may include increases in equity prices in anticipation of future dividends).

As described in Order 531,

15. With simplifying assumptions, the formula for the DCF model reduces to: \( P = \frac{D}{k - g} \), where “\( P \)” is the price of the common stock, “\( D \)” is the current dividend, “\( k \)” is the discount rate (or investors’ required rate of return), and “\( g \)” is the expected growth rate in dividends. For ratemaking purposes, the Commission rearranges the DCF formula to solve for “\( k \)”, the discount rate, which represents the rate of return that investors require to invest in a company’s common stock, and then multiplies the dividend yield by the expression \((1 + .5g)\) to account for the fact that dividends are paid on a quarterly basis. Multiplying the dividend yield by \((1 + .5g)\) increases the dividend yield by one half of the growth rate and produces what the Commission refers to as the “adjusted dividend yield.” The resulting formula is known as the constant growth DCF model and can be expressed as follows: \( k = \frac{D}{P} (1 + .5g) + g \).

Of course, the key determinant of discounted expected returns is the forecast of future dividend growth. FERC uses what it labels as the two-step DCF method, and describes the growth rate formula as

17. The Commission developed the two-step DCF methodology used for determining the cost of capital for individual gas and oil pipelines in a series of orders during the mid1990s. Under that methodology, the Commission determines a single cost of equity estimate for each member of a proxy group. For the dividend yield component of the DCF model, the Commission derives a single, average dividend yield based on the indicated dividend and the average of the monthly high and low stock prices over a six-month period. The Commission uses a two-step procedure for determining the constant dividend growth component of the model, averaging short-term and long-term growth estimates. Security analysts’ five-year forecasts for each company in the proxy group, as published by the Institutional Brokers Estimate System (IBES), are used for determining growth for the short term; earnings forecasts made by investment analysts are considered to be the best available estimates of short-term dividend growth because they are likely relied on by investors when making their investment decisions. Long-term growth is based on forecasts of long-term growth of the economy as a whole, as reflected in GDP. The short-term forecast receives a two-thirds weighting and the long-term forecast receives a one-third weighting in calculating the growth rate in the DCF model.\(^4\)

\(^3\) Ibid, p 9.
\(^4\) Ibid p 10.
The selection of proxy groups is a contentious matter (as it is in the present case) that is usually framed in relation to arguments about risk. However, in competitive markets, companies are not generally assumed to grow at the same rate as gross domestic product; rather their growth prospects are assumed to reflect comparative performance in revenue growth reflecting customer preference and earnings margin relative to revenue. In other words, in competitive markets, companies might be said to experience comparative performance risk. The Commission is therefore entitled to consider performance in establishing authorized return on equity.

Because a specific system of evaluating relative performance of a utility should be done with care and broad stakeholder involvement, I do not recommend making a formal change in practices in the present case. Rather, the Commission can generally consider performance in this case and should initiate a stakeholder process following on from its preparation of the PBR Report to facilitate its adoption of such criteria in the Company’s next general rate case.

Q. **How should the Commission consider the Company’s comparative performance on broad criteria in authorizing rate recovery of executive and employee incentive programs?**

A. Given that the Company is an effective monopoly and not subject to competition, and that its financial performance is determined by how it actually performs as compared to what it persuades the Commission is reasonable, incentives based on financial performance are as much an incentive to overstate expected costs to the Commission or to underspend what is needed to deliver results for customers (e.g., reducing tree trimming below needed levels
to improve financial performance) as it is to pursue cost-effective performance serving customer and societal values.

A systematic performance assessment for the Company based on metrics that are directly important to customers and society will provide a better incentive structure that is less subject to misallocation of effort than incentives based on short-term financial performance. The Commission should therefore follow a simple “bright line” standard that rate recovery will be allowed for incentives tied to affordability, reliability, pollutant emissions, and other criteria directly measuring the Company’s performance for its customers and society and that incentives tied to Company financial performance must be included in return on equity and effectively borne by holders of common stock. Generally, affordability, reliability, pollutant emissions, and any other performance criteria used in incentive compensation programs should be evaluated based on the Company’s comparative performance to other electric utilities both nationally and within the State of Michigan. The Commission may want to establish a stakeholder process following on from its preparation of the PBR Report to facilitate its acceptance of such criteria in the Company’s and other utilities’ next general rate cases.

Q. How should the Commission consider the availability of specific performance incentives when applying broad performance criteria to the authorized return on equity and any executive or employee incentive compensation plans?

A. At page 23 of its PBR Report, the Commission concludes amongst other recommendations that “well-designed PBR should include both positive incentives (rewards for good performance) and negative incentives (for unacceptable performance such as reduced customer service and service quality) in order to improve utility performance.” I concur
with that recommendation. However, Michigan law and the Commission have established
or are considering a number of exclusively positive incentives such as for energy waste
reduction, demand response, and use of power purchase agreements. Because incentives
are paid by customers, there is great risk that these incentives increase rates and provide
“rent” to the utility for its monopoly position rather than providing the utility an incentive
to perform well while also providing only a reasonable rate of return.

For this reason, I recommend that the Commission begin to implement an approach
wherein a utility achieving “ordinary” performance on aspects of its performance for which
only positive incentives are available has the opportunity to achieve “ordinary” returns on
equity through combined base return on equity and incentive income but that a poor-
performing utility will earn less than “ordinary” combined returns and a utility that
performs extraordinarily on incentivized aspects of its performance will earn extraordinary
combined returns. This approach will need to be approached carefully so as not to ratchet
down authorized returns based on improvements in individual utility performance, thereby
undoing the incentive for improved performance.

As a first step in this direction, I recommend that the Commission direct its Staff to work
with the regulated utilities and other stakeholders to establish an additional rate-case filing
requirement that will reveal to the Commission as part of each utility filing the range of
potential returns available to the utility based on its combined base return on equity and
revenue incentives.

Q. What aspects of the Company’s comparative performance on broad criteria should
the Commission consider?

A. On March 13, 2015, Governor Rick Snyder presented a special message to Michiganders and the Michigan Legislature entitled “Ensuring Affordable, Reliable, and Environmentally Protective Energy for Michigan’s Future.” While the Governor’s formulation of utility performance in that message was tailored to the time and place, it also reflects generally accepted performance criteria for an electric utility: affordability, reliability, and pollutant emissions.

The United States Department of Energy’s Energy Information Administration ("EIA") requires most electric utilities to annually submit data bearing on affordability, reliability, and pollutant emissions and publishes those data via its web site. This makes it feasible for the Commission to objectively consider the performance of Michigan’s regulated electric utilities compared to the performance of utilities serving other states as well as to compare the performance of the various Michigan electric utilities. Because these data are reported consistently over time, it is also feasible for the Commission to objectively consider performance trends over time.

Q. How would you characterize the Company’s performance with respect to affordability?

A. Exhibit CARE-1 consists of a series of graphs comparing the performance of Michigan’s electric utilities in aggregate to those in other states and comparing the performance of

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6 [www.eia.gov](http://www.eia.gov)
most of Michigan’s electric utilities, for calendar year 2017. These data were obtained from
the EIA website, and are the most recent such data they have released.

Due to the variety and complexity of rate designs amongst utilities and customer classes,
EIA’s practice is to report cost as the ratio of total revenue from a customer class to total
energy delivered to that customer class. As can be seen in CARE-1, in 2017 Michigan had
the 12th highest average cost of electricity for residential customers, 14th highest average
cost of electricity for commercial customers, and 24th highest average cost of electricity for
industrial customers when compared to the other states and the District of Columbia. When
compared to the neighboring states of Ohio, Indiana, Illinois, Wisconsin, and Minnesota,
in 2017 Michigan had the highest cost of electricity for residential customers, had the
highest cost of electricity for commercial customers, and had a lower cost of electricity for
industrial customers than any of these states except Illinois and Ohio.

Exhibit CARE-1 also shows that in 2017 UPPCO’s cost of electricity for residential
customers was 2nd highest of all Michigan utilities, cost of electricity for commercial
customers was highest of all Michigan utilities, and cost of electricity for industrial
customers was far below the average for all Michigan utilities.

Overall, Michigan’s cost of electricity is above that in most states, but is about median for
industrial customers, high for commercial customers, and very high for residential
customers. UPPCO follows that pattern but is more extreme across customer classes than
the Michigan average.

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7 www.eia.gov
In order to gain further understanding of this comparison, I examined similar affordability data since 2007, and show UPPCO’s average cost of electricity by class as a percent of Michigan average cost of electricity by class in the following graph.

![UPPCO Cost of Electricity Relative to Average Michigan Utility](chart.png)

Clearly, UPPCO’s cost of electricity has gotten worse compared to the whole of Michigan since 2014.

**Q. How would you characterize the Company’s performance with respect to reliability?**

**A.** The EIA measures overall reliability by the System Average Interruption Duration Index ("SAIDI"), which effectively measures the average number of minutes per year that the average electricity customer is without power. SAIDI can then be viewed as the product of the System Average Interruption Frequency Index ("SAIFI"), which effectively measures the number of outages per electric customer per year, and the Customer Average Interruption Duration Index ("CAIDI"), which effectively measures the average time to restoration of power when a customer experiences an outage. Each of these statistics excludes very short interruptions. Each of these can be reported with or without Major
Event Days. Major Event Days are calendar days when more than 5% of a utility’s customers experience an interruption, and can be thought of as reflecting major storms. In its own presentation of reliability data, the Company emphasizes indices excluding Major Event Days. I included Major Event Days for evaluating utility performance because these are an important part of the customer experience.

Exhibit CARE-1, pages 7 through 18, display the reliability performance of Michigan utilities in 2017. Michigan had the 6th highest minutes of outage per customer including Major Event Days and the 8th highest minutes of outage per customer excluding Major Event Days in 2017, when compared to other states and the District of Columbia. Michigan was 22nd highest in the frequency of outages including Major Event Days and 28th highest in the frequency of outages excluding Major Event Days in 2017. Unfortunately, Michigan was 4th worst in the time to restore power when a customer experienced an outage when including Major Event Days and 2nd worst when excluding Major Event Days. When compared to the neighboring states of Ohio, Indiana, Illinois, Wisconsin, and Minnesota in 2017, Michigan was worst in minutes of outage per customer, either including or excluding Major Event Days; all of these states had lower interruption frequencies including Major Event Days while Ohio and Indiana had higher interruption frequencies when excluding Major Event Days; and no neighboring state had experienced longer average time to restore a customer, whether including or excluding Major Event Days.

Exhibit CARE-1 also shows that UPPCO’s customers experienced significantly fewer minutes of interruption including Major Event Days than the customers of the average Michigan electric utility in 2017, reflecting that they experienced higher than average
number of interruptions including Major Event Days per customer in 2017 but a shorter average time to restore power after an interruption, including Major Event Days, as compared to other Michigan utilities. Exhibit CARE-1 further shows that UPPCO’s customers experienced somewhat fewer minutes of interruption excluding Major Event Days than the customers of most other Michigan electric utility in 2017, reflecting that they experienced more than the average number of interruptions excluding Major Event Days per customer in 2017 but a shorter average time to restore power after an interruption, excluding Major Event Days, as compared to other Michigan utilities.

Overall, Michigan’s electric reliability performance compared to the other states and the District of Columbia is worse than average, but this reflects better than average performance on the frequency of interruptions and very poor performance in the restoration of power following an outage. UPPCO’s reliability is somewhat better than the average in Michigan with respect to all three measures of reliability. I have examined similar reliability data since 2013, and UPPCO experienced reduced frequency of interruptions excluding Major Event Days in the last few years and stable time to restore service after an outage, whether including or excluding Major Event Days.

Q. How would you characterize the Company’s performance with respect to pollutant emissions?

A. Comparisons of individual utility performance with respect to emissions is difficult because for many utilities, generation is not only for sales to their own customers and sales to customers are not only from the utility’s own generation. This is particularly true for utilities in wholesale energy markets where the utility may be a net importer of power at
some times and a net exporter at other times. It is also true where utilities have bilateral power contracts. Thus, the attribution of emissions to power delivered to a utility’s customers can be ambiguous. I therefore defer consideration of UPPCO’s emissions to its upcoming Integrated Resource Plan. Nonetheless, since this is the Company’s first general rate case following the Commission’s PBR Report, it may be instructive for the Commission to be aware of the emissions performance of Michigan’s overall generation fleet.

Exhibit CARE-1, pages 19 through 21 show average emissions of carbon dioxide, sulfur dioxide, and nitrogen oxides per gigawatt-hour of electric energy generated by state in 2016. Michigan was 20th in carbon emissions, 8th in sulfur dioxide emissions, and 20th in nitrogen oxide emissions. These rankings all reflect improvements resulting primarily from Consumers Energy’s retirement of the “classic 7” coal units early in 2016. When compared to the neighboring states of Ohio, Indiana, Illinois, Wisconsin, and Minnesota in 2016, Illinois and Minnesota had significantly lower carbon dioxide emissions rates than Michigan, while Indiana, Ohio, and Wisconsin were significantly higher; only Ohio had a higher sulfur dioxide emissions rate than Michigan; and Indiana and Ohio had significantly higher nitrogen oxides emissions rates, Wisconsin and Minnesota had slightly lower nitrogen oxides emissions rates than Michigan, and only Illinois had significantly lower nitrogen oxides emissions rates than Michigan.

Overall, Michigan’s 2016 performance on emissions rates was somewhat worse than in most states, with high sulfur oxide emissions standing out. While these results are worse than much of the country, these results do reflect steady improvement in emissions rates and some improvements in comparative emissions rates over the last decade, primarily
through the retirement of old coal plants with significant replacement by energy efficiency
improvements and increasing renewables generation.

Since most of UPPCO’s power supply is obtained through bilateral and market purchases,
presumably UPPCO’s contributions reflect averages in the regional market with the notable
exception of its higher use of hydroelectric generation within its service territory.

Q. Based on the electric utility performance data you have just presented, what should
the Commission emphasize in the present case?

A. The Commission should be concerned about UPPCO’s overall costs and especially costs
for residential and commercial customers. The Commission should be supportive of
continued improvements in reliability but careful about costs of reliability improvements.
The Commission should also be supportive of continued improvements in emissions rates.

Based on UPPCO’s overall performance, the Commission should be targeting return on
equity somewhat below national average but within the “zone of reasonableness”,
reflecting that UPPCO has much higher costs of electricity and somewhat lower reliability
than utilities across the country and higher costs of electricity but better reliability than
most Michigan utilities.

The Commission’s most recent decisions regarding return on equity are likely too
generous, given the Company’s performance. The following table\(^8\) shows that the
Commission’s return on equity decisions have been amongst the most generous in the

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\(^8\) Obtained from 25 October 2018 report by S&P Global, available by subscription at
country despite the comparative performance of Michigan’s utilities.

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**Delivery only cases**

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</table>
Q. How should the priorities you recommend to the Commission be reflected in the particulars of the present case?

A. In this case, UPPCO proposes a substantial increase in overall revenue, reflecting continuing challenges with legacy costs and financial structure, despite recent improvements in its power supply costs. The Commission should vigorously seek to reduce UPPCO’s required revenue.

UPPCO’s cost of service study indicates that revenue responsibility should shift significantly away from residential and small commercial customers and onto larger commercial and industrial customers. However, UPPCO shies away from the implications of the cost of service study and mitigates impacts on its commercial and industrial customers through the allocation of certain revenue credits. The Commission should direct UPPCO to more equitably allocate revenue credits and implement rates that more fully reflect cost of service.

While these priorities emerge from UPPCO’s comparative performance on metrics that are available for national comparison, there are also important rate design issues at stake in this case.

IV. UPPCO’s PROPOSAL TO CHANGE REVENUE CREDIT OBLIGATIONS

Q. Please explain UPPCO’s proposal to change its revenue credit obligations in the future.

A. Case U-17564 before the Commission sought approval of the transfer of UPPCO from its status as a wholly-owned subsidiary of Integrys Energy Group, Inc. to ownership by Upper Peninsula Power Holding Company, itself owned by Balfour Beatty Infrastructure
Partners, L. P.. Settlement of Case U-17564 was approved by the Commission in its order of June 6, 2014. Condition 15 of that settlement reads:

(15) Following closing of the Proposed Transaction, UPPCo shall provide a revenue offset of $26 million spread over six consecutive years to be applied to the distribution portion of each applicable tariff, effective with the date rates go into effect as approved in its next base rate case;

Parties to the settlement included CARE, on whose behalf I am testifying in the present case.

$26 million spread evenly over six years is $4,333,333 per year and that revenue credit schedule is currently in effect. In UPPCO’s last general rate case, U-17895, an annual revenue credit of $4,333,333 was included in the determination of UPPCO’s rates with 2016 as the first year of the six-year period of application.

In the present case, UPPCO proposes to change that revenue credit, supported through testimony by Gradon R. Haenel. The essence of this proposal, with various adjustments related to taxation, is that UPPCO proposes to reduce the remaining balance of the credit by the revenue equivalent of its claimed income deficiencies in 2016 and 2017 and to amortize that remaining balance evenly over the years 2018 through late 2022, applying a revenue credit of $2,584,802 in each of those years.

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9 Direct testimony of Gradon R. Haenel, page 4 line 21 through page 8, line 18.
Q. Do you agree with UPPCO’s proposal concerning this revenue credit?

A. No. It is invalid for three reasons.

First, this proposal is not consistent with the understanding of the parties to the settlement. The settlement called for an explicit revenue credit and did not contemplate that the credit would be used to offset any revenue deficiency experienced by UPPCO. I think it unlikely that UPPCO would have proposed an increase in future revenue credits had it experience a revenue sufficiency in 2016 and 2017. In short, a deal is a deal and UPPCO’s proposal is to break the deal struck in settlement of U-17895.

Second, UPPCO’s proposal amounts to retroactive ratemaking. The Commission approved rates for UPPCO in U-17895 based on the Company’s representations as to its revenue requirements and cost of service, as contested by other parties, and established the rates that were in effect for the balance of 2016 and continuing to the present. Adjusting the revenue credits for 2016 and 2017 as proposed by UPPCO is a retroactive adjustment of those credits, which if applied prospectively would have resulted in different rates being set in U-17895. Presumably, rates based on the revenue credits UPPCO now proposes to apply retroactively to 2016 and 2017 would have still produced revenue deficiencies of similar amounts.

Finally, the settlement specifies that the revenue offset is “to be applied to the distribution portion of each applicable tariff”. UPPCO’s proposal to retroactively use revenue credits to offset its claimed income deficiencies does not systematically apply the revenue credits “to the distribution portion of each applicable tariff” but instead to the combined production, transmission, distribution, customer service, and overhead portions of the
revenue deficiencies of the various rate classes.

Q. What do you recommend that the Commission do in response to UPPCO’s proposal to modify the revenue credit schedule established in U-17895 to implement condition (15) of settlement approved by the Commission in U-17564?

A. The Commission should deny this request and continue to apply a revenue credit of $4,333,333 per year for six years from the implementation of rates at the end of U-17895.

V. COST OF SERVICE STUDY

Q. Have you reviewed UPPCO’s cost of service study as proposed in the present case?

A. I have. I take exception to only one aspect of the UPPCO’s proposed cost of service study.

Q. What aspect of the cost of service study do you object to?

A. UPPCO allocates its production plant costs to rate classes based 75% on 12CP coincident demand and 25% on annual energy at generation. I object to that practice in general as not being based on analysis of cost causation and find that it is particularly erroneous when applied to UPPCO.

Q. What production plant costs does UPPCO allocate based on this method?

A. UPPCO’s cost of service study is presented in Exhibit A-16 Schedule F1 and is supported by a confidential work paper “CONFIDENTIAL UPPCO COS 2019 wo MS_FINAL_FINAL Protected” that was provided by UPPCO to CARE in response to discovery 1-CARE-UPPCO-10. Based on my examination of that work paper, the cost allocator labeled as DPROD is the allocator that directly allocates costs based 75% on

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10 See Exhibit CARE-2.
12CP coincident demand and 25% on annual energy at generation. There are, of course certain derived allocators of indirect costs that would also be affected by a change in this allocator.

Of the $105,398,076 Electric Plant in Service included in the cost of service study rate base, 0.14% is identified as for steam production, 94% is identified as for hydraulic production, 5.64% is identified as for other production combustion, and 0.22% is for Production Energy. These ratios then generally flow through to depreciation expense, returns, taxes, and indirect costs with certain adjustments. Of the $3,938,022 in production operations and maintenance included in the cost of service study expenses, 0.78% is for steam production, 98.25% is for hydraulic production, and 0.97% is for combustion turbine production.

It is therefore clear that UPPCO’s production costs that are allocated 75% based on 12 CP coincident demand and 25% annual energy at generation are overwhelmingly for hydraulic production.

The total annual expense allocated based on demand is not visible in the Company’s Exhibits in this case but can be found in the work paper “CONFIDENTIAL UPPCO COS 2019 wo MS_FINAL_FINAL Protected” on tab “UNBUNDLED” in cell D248.

Q. **What production plants are included in UPPCO’s production plant costs?**

A. UPPCO does not detail these plants in the present case, but its production plants are described in its PSCR Plan case U-20229 which is currently underway and in its recently
filed Integrated Resource Plan in Case U-20350.

UPPCO has two oil-fueled plants: Portage and Gladstone. As described in U-20229 Exhibit A-7, Portage has 17.1 MW capacity and Gladstone has 15.3 MW capacity. U-20229 Exhibit A-6 shows production forecasts of 1,091 MWH from Portage and 120 MWH from Gladstone. However, UPPCO discloses in its Application in Case U-20350 that the Portage plant failed in November 2018\(^{11}\) and has an uncertain future.

UPPCO has four hydraulic generating units: Victoria, Prickett, McClure, and Hoist. As described in U-20229 Exhibit A-5, Victoria has net capability of 12 MW, Prickett has net capability of 2 MW, McClure has net capability of 8 MW, and Hoist has net capability of 3 MW. However, as shown in U-20229 Exhibit A-7, only the Victoria unit is used by UPPCO in 2019 to meet its capacity obligations to the Midcontinent Independent System Operator.\(^{12}\) U-20229 Exhibit A-6 shows 2019 production forecasts of 52,295 MWH from Victoria, 6,592 MWH from Prickett, 34,747 from McClure, and 11,886 from Hoist. Monthly production forecasts shown in U-20229 Exhibit A-2 show that production from these hydraulic units is spread throughout the year but is highest in spring and lowest in summer (the period during which MISO’s system peak typically occurs) and fairly low in winter (when UPPCO’s system peak often occurs).

**Q.** How should UPPCO’s production plant costs be allocated in its cost of service study.

**A.** That portion of UPPCO’s production plant costs that is for Gladstone and Portage is clearly for peaking and should be allocated entirely based on demand.

\(^{11}\) U-20229 Application, page 2, paragraph 5.

\(^{12}\) See also discussion of this in U-20350, Application page 6, paragraph 13.e.
That portion of UPPCO’s production costs that is for Prickett, McClure, and Hoist provides no capacity value and should therefore not be allocated based on 12 CP demand, but entirely on energy.

Hydraulic production using in-stream dams with limited storage capacity and license restrictions requiring nearly run-of-river operation is directly dependent on available flows. These are the conditions under which all of UPPCO’s hydraulic production units operate. The operational data for these units clearly demonstrates that even if considered for capacity credit, as in the case of Victoria, that capacity value is incidental to the resource-dependent generation of energy coincident with system peak demand. It is therefore inappropriate to use an arbitrary rule of thumb that 75% of production plant costs are for capacity and 25% are for energy when the production plant in question is predominantly hydraulic power.

In order to establish a more reasonable allocation of production plant costs to demand and energy, I prepared a calculation that is available in a confidential work sheet that uses the total cost of production plant as it appears in the Company’s confidential cost of service work paper and allocates costs based on 12 CP coincident demand equal to cost of new entry for a combustion turbine, as determined by MISO. MISO considers this calculation to provide the maximum cost of capacity in its administration of resource adequacy, so it is unreasonable to allocate costs materially exceeding this amount to the purpose of providing adequate capacity. In doing this calculation, I have included the capacity provided by Gladstone and Portage, even though the actual costs of capacity from these

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13 See Exhibit CARE-3 MISO 2018-19 Cost of New Entry Update
units is far below cost of new entry and even though the capacity available from the Portage plant is questionable. I conclude that 18.2% of UPPCO’s production plant expenses should be allocated to 12 CP demand and 81.8% should be allocated to energy. As a reasonable approximation using a “rule of thumb”, I allocated 20% of UPPCO’s production plant expenses to 12 CP demand and 80% to annual energy.

Q. What effect does this change in the allocation of production plant costs have on revenue responsibility of the various rate classes?

A. In order to determine the significance of this change in allocation of production plant costs, I made the appropriate changes in cells D45 and D46 of tab “Allocation Factors Data” of “CONFIDENTIAL UPPCO COS 2019 wo MS_FINAL_FINAL Protected”. Exhibit CARE-4 presents a comparison of the revenue responsibility of the various rate classes based on the cost of service study as filed by UPPCO and with this modification of the production plant allocator.

VI. ALLOCATION OF REVENUE CREDITS

Q. You indicated earlier that you have concerns about the UPPCO’s proposed allocation of revenue credits in this case. How has UPPCO proposed to allocate revenue credits?

A. There are two revenue credits to be considered in this case. The first of these is the $26 million credit to be provided over a six-year period as agreed in the settlement of U-17564. As I discussed earlier, UPPCO proposes to reduce the annual amount of this revenue credit from $4,333,333 to $2,584,802. In addition, Exhibit A-11, Schedule A1, line 22 shows a credit of $694,563 related to deferred pension and transition costs that was adopted by the
Commission in U-17895. Thus, the total revenue credits that UPPCO proposes to allocate in the present case is $3,279,365.

As briefly discussed by Witness Stocking, UPPCO proposes to allocate these revenue credits “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.” 14 Exhibit A-16 Schedule F2 shows UPPCO’s total proposed revenue by rate schedule but does not show how this was derived. Exhibit CARE-5 shows for each rate class the present revenue used in the cost of service study15 (which differs somewhat from the present revenue shown in Exhibit A-16 Schedule F2), the revenue deficiency calculated in the cost of service study as filed,16 the resulting revenue responsibility, the Total Proposed Revenue from Exhibit A-16 Schedule F2, and the difference between the revenue responsibility determined in the cost of service study and UPPCO’s Total Proposed Revenue. The total of differences between the revenue responsibility determined in the cost of service study and UPPCO’s Total Proposed Revenue is $3,398,359 consisting of $3,279,365 of revenue credits and $118,994 consisting of differences between the present revenue used by UPPCO in its cost of service study and in Exhibit A-16 Schedule F2 and other unexplained differences.

Upon examination of Exhibit CARE-5, it is clear that UPPCO set proposed revenue for the residential class in total (Rates A-1, A-2, and AH-1) to the revenue responsibility determined in the cost of service study for those rate schedules in total but made some different allocations amongst these customer classes, and set proposed revenue for rate

14 Direct testimony of Eric W. Stocking, page 14 line 17 through page 15 line 5.
15 Exhibit A-16, Schedule F1, line 6 of pages 2 through 4.
16 Exhibit A-16, Schedule F1, line 76 of pages 6 through 8.
schedules WP-3 and RTMP at their revenue responsibility as determined in the cost of service study and allocated the revenue credits to the remaining classes. They further adjusted the rates proposed for the remaining classes such that class C-1 will pay about $2.6 million more than its revenue responsibility and the SL classes will pay about $221 thousand more than its revenue responsibility, according to the cost of service study. Rate classes P-1, Cp-U, and Z-3&Z-4 benefit from all of the revenue credits and from the extra revenue proposed from rate schedule C-1.

Q. **What are your concerns about this proposed allocation of the revenue credits to the various rate classes?**

A. I have two basic concerns. First, this allocation of the revenue credits agreed in settlement of U-17564 is contrary to the terms of that settlement, which specify that these credits are “to be applied to the distribution portion of each applicable tariff”. Although the intended allocation of the deferred pension and transition cost credit is less explicitly defined, these credits should presumably be allocated to rate classes consistent with the allocation of pension and transition costs. Second, this allocation fails to allocate the credits to those classes whose rates are most out of harmony with rates of other utilities.

Q. **How should these revenue credits be allocated?**

A. Exhibit A-16, Schedule F1, pages 158-160 summarizes required revenue at the proposed rate of return in rows 5 through 33. I calculated the required revenue under the headings of “Distribution Costs” and “Customer Distribution Costs” for each rate schedule and then computed the percentage of these costs that are allocated to each rate schedule. These percentages are the appropriate basis for allocating the revenue credit agreed in settlement of U-17564.
Because the pension costs and transition costs that gave rise to the deferred pension and transition costs are primarily related to distribution and customer service functions, I similarly computed the percentage of total distribution and customer costs for each rate schedule. These percentages are an appropriate basis for allocating the deferred pension and transition cost credit. Exhibit CARE-6 displays these percentages and the amounts of revenue credit that should be allocated to each rate schedule using an annual U-17564 credit of either $2,584,802 as proposed by UPPCO in the present case or $4,333,333 as I testified above is appropriate, as well as the amounts of revenue credit that should be allocated to each rate schedule in relation to the $694,563 credit for deferred pension and transition costs.

VII. REVENUE RESPONSIBILITY

Q. Based on your analysis of the allocation of production plant costs, your allocation of $4,333,333 revenue credits pursuant to U-17564, and your recommendation regarding the allocation of credits for deferred pension and transition costs, what is the revenue responsibility of each rate schedule?

A. First, it should be noted that this analysis is premised on the revenue requirements proposed by UPPCO and will need to be modified in response to any adjustments that the Commission adopts. Exhibit CARE-7 shows for each rate schedule the present revenue from the cost of service model as filed by UPPCO, the revenue responsibility from the cost of service model as filed by UPPCO but with the allocation of production plant costs based on 20% to 12 CP coincident demand and 80% to annual energy, consistent with Exhibit CARE-4, the revenue credit pursuant to U-17564 at an annual rate of $4,333,333 consistent
with Exhibit CARE-6, and the revenue credit for deferred pension and transition costs at an annual rate of $694,563 consistent with Exhibit CARE-6.

Q. Do you recommend that rates be designed to reflect the revenue responsibilities shown in Exhibit CARE-7?

A. Yes.

Q. Some of the changes in rates implied by Exhibit CARE-7 are substantial. Are you concerned about this degree of change?

A. I am not distressed by the degree of change implied by Exhibit CARE-7. These changes rectify rates that I believe have been systematically unfair and unjust for a number of years. Furthermore, UPPCO’s rates have been changing by large amounts in recent times. UPPCO President and CEO James C Larsen testified in the present case that due to the mechanics of recent rate changes, “some larger usage customers have experienced significant reductions”.17 In response to a discovery request from CARE,18 he provided the following table elaborating on this point:

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18 Exhibit CARE-8. UPPCO response to 1-CARE-UPPCO-001
The rate classes that would experience the largest percentage increases pursuant to my recommendations as summarized in Exhibit CARE-7 are the rate classes that benefited most from recent changes, as summarized by Mr. Larsen. It is important to note that a 25% rate reduction, followed by a 41% increase over that reduced rate (as for rate class P-1) is only about a 6% net increase over the entire process. The Commission should therefore not be dissuaded from adopting the revenue responsibilities in Exhibit CARE-7 due to the seemingly large percentage increases over present revenue shown in Exhibit CARE-7.

I recognize that the Commission often moderates changes in rates through a gradual transition. In the event that the Commission is not prepared to adopt these changes in immediate rates, I recommend that rates based on Exhibit CARE-7 be adopted and that an explicit rate realignment plan be adopted for systematic transition to these rates over a short period of time.
VIII. RATE DESIGN

Q. Aside from the changes in proposed revenue embodied in Exhibit CARE-7, do you support UPPCO’s approach to rate design?

A. I have one broad concern about UPPCO’s approach to rate design and a few specific concerns regarding certain rate classes. My broad concern is UPPCO’s proposal to significantly increase fixed monthly charges within the rate design for most rate schedules.

Q. Please explain UPPCO’s proposal to increase fixed monthly charges.

A. As shown in Exhibit A-16, Schedule F-3, pages 1 through 13, UPPCO proposes increases in monthly service charges. UPPCO’s justification for these changes is limited. James C. Larsen testifies

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.

Eric W. Stocking testifies

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

19 Direct testimony of James C. Larsen, page 10 lines 2-16
20 Direct testimony of Eric W. Stocking, page 18, lines 5-12
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.

The following table summarizes the present and proposed monthly service charges for each
rate class together with the customer costs per month per customer presented on pages 162
through 164 of Exhibit A-16, Schedule F1.

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**Q. What are your concerns about these proposed monthly service rates?**

**A.** The customer costs used to develop the customer costs per customer per month shown on
page 162 of Exhibit A-16, Schedule F1 include distribution service laterals, metering,
meter reading, customer accounting costs, sales, and service. These are appropriate cost
categories for inclusion in the monthly customer service charge, consistent with the
Commission’s historical reasoning regarding such charges. However, I have two concerns
about this subject. First, these costs are in fact relatively high. Second, Mr. Larsen’s
reasoning is faulty and should be ignored but suggests an alternative for future
consideration.

Careful examination of the components of customer costs in the cost of service study shows
that these are dominated by large costs in the category labeled “CUST ACCT, SALES, &
SERVICE COMPONENT”. The costs in this category include costs associated with
UPPCO’s relatively new billing system, call center, and other expenditures associated with
its transition to an independent operating company and includes customer service activities
associated with its billing problems during the historic test year. The Commission should
therefore consider maintaining current monthly service charges or authorizing more
moderate increases pending a future demonstration that the high costs in this category are
prudent and reasonable and persistent. The Commission should also direct the Company to
provide with its next general rate case that is filed after completion of its AMI solution a
detailed analysis of its customer account, sales, and service costs and its efforts to control
those costs.

Mr. Larsen’s reasoning is faulty and should be ignored. It is true that using a higher monthly
service charge will lead to a lower volumetric charge to achieve the same total revenue
from a customer class. However, Mr. Larsen fails to provide any reason that this is a
desirable result. He also fails to note that this increases bills for low-volume customers and
that low-volume customers tend to be low-income customers, so that increased fixed
charges have a disparate impact on low-income customers.

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21 See for example, the public comments filed in U-18455
Mr. Larsen also asserts that a higher monthly service fee “reduces the overall bill for full
time residences and will increase the bill for seasonal residences.” This is likely true and I
have some sympathy for the idea of shifting cost responsibility in some way, but because
an increase in the monthly service charge also introduces other distortions in rates, a
monthly minimum bill would be a better way to shift costs from full-time residents to
seasonal customers.

Mr. Larsen also asserts that this charge “is consistent with other utilities in the Upper
Peninsula who have low customer usage like UPPCO.” Whether or not his assertion about
the comparison of UPPCO’s proposed fixed monthly charges to those of other utilities is
empirically accurate, if the monthly service charges are based on customer costs as shown
in pages 162-164 of Exhibit A-16, Schedule F1, then the amount of these costs does not
depend on monthly usage and this comparison is irrelevant.

Q. What action do you recommend to the Commission with respect to UPPCO’s
proposed increases in monthly service charges?

A. I recommend that the Commission direct the Company to file a detailed analysis of its
customer account, sales, and service costs and its efforts to control those costs, as part of
its next general rate case filed after it completes implementing its AMI solution. In the
interim, I recommend that the Commission either leave monthly service charges unchanged
or allow a more moderate increase than that proposed by the Company, perhaps only half
the difference between the current monthly service charge and the estimated customer cost
per customer per month produced in the cost of service study.

Q. You indicate that you also have specific concerns about rate design for certain rate
classes. What are those concerns?

A. I have specific concerns about interruptible demand rates in the Cp-U and WP-3 rate schedules and about the heating tariffs AH-1 and H-1.

With respect to the interruptible demand rates in the Cp-U and WP-3 rate schedules, I reference my recent testimony in UPPCO’s 2019 PSCR Plan Case U-20229. This testimony shows that at present rates, interruptible customers are benefiting from discounted tariffs at an excess cost to other customers of at least $830,489. UPPCO and the Commission should consider reform of the Cp-U and WP-3 interruptible tariffs as part of the rate design for those classes in the present case.

With respect to the heating tariffs AH-1 and H-1, UPPCO should consider making conceptual changes in future rate cases. It is true that UPPCO has relatively low usage per residential and small commercial customer and that the allocation of non-volumetric costs over this lower volume per customer is part of the reason for its high rates. This fact does not invalidate either the recovery of those costs through volumetric charges nor of energy waste reduction programs that will serve to reduce total customer costs but also increase rates. However, it does point to the opportunity to reduce rates and total costs for its customer’s current uses of electricity through strategic electrification. Increasing sales to current distribution customers through electrification of space heating, water heating, and transportation can both provide benefits to the participating customers and dilute rates for non-participating customers. Notably, since most fixed costs that can be diluted through increased sales are distribution and customer service costs, increases in transmission sales will not provide such a benefit to existing customers. I therefore recommend that in its next
general rate case, UPPCO should examine changes to the AH-1 and H-1 tariffs to incorporate opportunities for fuel-switching for space heating, water heating, and transportation to increase electricity sales to residential and small commercial customers. The tariffs and any incentives provided must be constructed so that they provide some benefit to the non-participating customer and are still attractive to potential participants.

**IX DISTRIBUTED GENERATION**

**Q.** UPPCO proposed a distributed generation tariff in the present case. Please summarize that proposal.

**A.** 2016 PA 341 directed the Commission to study and report on an appropriate distributed generation tariff, reflecting cost of service, and directed that each regulated utility must include such a tariff in its next general rate case filed after June 1, 2018. In Case U-18383, the Commission adopted guidance for utilities based on an inflow-outflow construct and ordered each utility to include a compliant tariff in its next general rate case filed after June 1, 2018, while allowing the utility to propose an alternative approach. UPPCO’s proposed distributed generation tariff is responsive to that order and is based on an inflow-outflow construct as guided by the Commission.

Witnesses Haenel\(^\text{22}\) and Stocking\(^\text{23}\) provide only introductory testimony regarding the distributed generation tariff, so the tariff itself is the basis of my evaluation.

UPPCO proposes to add a provision to its existing parallel generation (net metering) tariffs PG-1M, PG-2, and PG-3 closing those to new participation at the conclusion of the present

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\(^{22}\) See Direct testimony of Gradon R. Haenel, page 17 line 12 through page 18 line 10.

\(^{23}\) See Direct testimony of Eric W. Stocking, page 12 lines 1-4.
case and allowing customers already participating in those tariffs to continue until 10 years
after initial participation, or at the customer’s option switch to the distributed generation
tariff before the end of the 10-year period.

UPPCO proposes a new distributed generation ("DG") rider to implement the provisions
of 2016 PA 342 and 2016 PA 341. This rider is available to any UPPCO customer on a
metered tariff, excluding riders, unless otherwise noted on that metered tariff. Pursuant to
the draft tariff, an UPPCO customer with an “Eligible Generator” on premise can purchase
inflow power at the standard rate for that customer and receive a bill credit for outflow
power at the standard power supply rate, with the limitations that outflow credits may only
be used to offset power supply costs, including PSCR adjustments, and any excess credits
must be carried forward to subsequent billing period(s).

An Eligible Generator must be a renewable energy system or a methane digester generator
with annual output limited to not exceed the customer’s annual energy consumption. For a
renewable energy system, capacity must be limited to 150 kW. For a methane digester,
capacity must be limited to 550 kW.

The proposed tariff also provides for an unspecified System Access Contribution per kW
of installed capacity, per month.

The tariff reflects provisions of 2016 PA 342 in limiting the aggregate participation of
UPPCO customers in the distributed generation program to 0.5% of UPPCO annual load
for eligible generators having individual capacity less than 20 kW, 0.25% for eligible
generators having individual capacity greater than 20 KW but less than 150 kW, and 0.25%
for methane digesters up to 550 kW. Application of these limits is based on first-come, first-served sequencing of customer applications for participation in the program.

Q. What is your evaluation of UPPCO’s proposed DG tariff?

A. The tariff as proposed by UPPCO generally comports with law and the Commission’s guidance and does so in a reasonable way. However, the System Access Contribution should be rejected as unreasonable and unjust. In addition, practical considerations related to Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (“PURPA”) would be best addressed by certain revisions of the proposed tariff that would be voluntary by UPPCO but would require Commission approval.

Q. Why should the System Access Contribution be rejected as unreasonable and unjust?

A. The System Access Contribution is a charge per kW of Eligible Generator capacity. But, an Eligible Generator reduces demand on the electrical system, at least at certain times, so the size of an Eligible Generator does not drive any cost to the utility. Thus, a charge based on the capacity of an Eligible Generator does not reflect cost causation. UPPCO has not articulated any correlation between the capacity of an Eligible Generator and any mode of cost causation, nor can I think of one. The capacity of an Eligible Generator is therefore an inappropriate billing determinant.

Further, UPPCO has not presented any evidence that a customer with an Eligible Generator who pays for inflow at the customer’s base rate and is credited for outflow at the corresponding power supply cost is paying less than that customer’s cost of service. Under the relevant statute and the Commission’s Order in U-18383, the tariff must reflect cost of service, so without a showing that a customer in these circumstances is failing to pay cost
of service, it would be unreasonable and unjust to charge an additional fee of any kind, let alone one based on a billing determinant that bears no discernable relationship to cost causation.

Q. What considerations related to PURPA would be best addressed by revisions of the proposed tariff?

A. Under provisions of PURPA, a utility such as UPPCO is obligated to purchase power from a qualifying facility (“QF”) under terms that are not discriminatory and at a price up to the utility’s “avoided cost”. Any Eligible Generator under UPPCO’s proposed tariff would be a PURPA QF.

Under PURPA, a utility must sell supplemental power to a PURPA QF on a non-discriminatory basis. This can be done by selling power to the PURPA QF at the rate that would otherwise apply to that customer and the utility would have a significant burden to demonstrate that any higher rate is not discriminatory. Thus, UPPCO’s proposed rates for inflow appear to be consistent with its obligation to provide supplemental power to a PURPA QF.

A PURPA QF can use power to serve its own load and sell the excess to the utility. Thus the power sold under PURPA would be the outflow, as defined in UPPCO’s proposed tariff. UPPCO’s avoided cost for PURPA contracts is established by the Commission, most recently in Case U-18094. In that case, avoided costs are established for energy and capacity, where capacity is measured consistent with the MISO resource adequacy construct. For variable resources, which would typically be the case with outflow from a customer with an Eligible Generator, MISO measures capacity as the average output
between 2pm and 5pm ET in the months of June, July, and August. Thus, avoided cost could be paid by applying the avoided energy cost to outflow at all times and an extra amount equivalent to the avoided capacity cost for outflow between 2pm and 5 pm ET in the months of June, July, and August. Whether the resulting avoided cost payments would be greater or less than the power supply rate UPPCO proposes in its DG tariff would depend on the relative amounts of outflow during and outside of the hours 2pm to 5pm ET in June, July, and August. It is very likely that the avoided cost determined under Case U-18094 would not differ much from the power supply rate used in this tariff.

Thus, the key difference between applying the proposed tariff to an Eligible Generator and applying PURPA to that customer is that under the DG tariff outflow is credited on the customer’s bill, while under PURPA it would ordinarily be a cash payment by UPPCO to the PURPA QF owner.

It is also noteworthy that under PURPA, UPPCO cannot limit the amount of power it takes from PURPA QFs in aggregate. It is my understanding that UPPCO is currently at the cap of 0.5% of load for distributed generation program participation by Eligible Generators with less than 20 kW capacity. However, any UPPCO customer with an Eligible Generator who cannot be accommodated within the program cap would nonetheless be entitled to very similar treatment as a PURPA QF. Further, a customer that would otherwise have an Eligible Generator but has a capacity greater than 150 kW that is not a methane digester would also be entitled to very similar treatment as a PURPA QF. A customer that would otherwise have an Eligible Generator but with a capacity greater than 550 kW would also be entitled to very similar treatment as a PURPA QF. Any customer that is eligible to
participate in the distributed generation tariff would be entitled to treatment as a PURPA QF even if there is space for them in the distributed generation program.

Thus, as a practical matter any UPPCO customer could acquire an Eligible Generator, pay the standard tariff rate on their inflow and be compensated by cash payments for the outflow as a PURPA QF. As a practical matter, the various restrictions on participation in the distributed generation program are only restrictions on the ability of the customer to take a bill credit for outflow rather than money payments.

A bill credit rather than money payment is beneficial to an UPPCO customer principally in that such a credit is not taxable income to the customer. A bill credit rather than a money payment would be beneficial to UPPCO primarily in that UPPCO avoids transaction costs for payments to the customer and taxable income reporting. A bill credit and a payment have the same effect on UPPCO’s net revenue. I therefore recommend that UPPCO agree to modify the proposed tariff to eliminate absolute system size limitations and program caps, and simply provide standard tariff rates for inflow and bill credits at power supply rate for outflow from any renewable energy system or methane digester with expected annual generation of no more than 100% of the customer’s annual consumption.

X. RECOMMENDATIONS AND CONCLUSION

Q. Please summarize your recommendations to the Commission.

A. I recommend that the Commission

(1) consider UPPCO’s comparative performance for customers and society in determining authorized return on equity, and on that basis choose a rate of return below the middle of the “zone of reasonableness” found through financial analysis;
(2) determine that UPPCO’s proposal to count past revenue deficiencies toward the revenue credit agreed to in Case U-17564 and implemented in U-17895 is unlawful, unreasonable, or both and that UPPCO must continue to provide an annual revenue credit of $4,333,333 for a period ending six years after implementation of rates as ordered in U-17895;

(3) determine that allocation of 75% of UPPCO’s production plant costs based on 12 CP coincident demand and 25% of UPPCO’s production plant costs based on annual energy does not reflect cost of service due to the particular characteristics of UPPCO’s generation fleet;

(4) further determine that an appropriate allocation of UPPCO’s production plant costs to customer classes is to base 20% of that allocation on 12 CP coincident demand and 80% of that allocation on annual energy;

(5) determine that revenue credit in fulfillment of the settlement approved by the Commission in U-17564 must be allocated to rate classes in proportion to the allocation of distribution costs to rate classes, per the terms of the settlement;

(6) determine that the revenue credit for deferred pension and transition costs established pursuant to Commission order in Case U-17895 is most appropriately allocated to rate classes based on combined distribution and customer service costs;

(6) determine that the revenue credit calculations presented in Exhibit CARE-6 are an appropriate basis for reducing revenue responsibility as otherwise determined in this case;

(7) either determine that the revenue responsibility determined through the cost of service study, less the appropriate revenue credits, are the appropriate basis for rate design
in this case or adopt rates on that basis with an explicit rate realignment plan using phased-
out surcharges and surcredits;

(8) either adopt rate design using present fixed monthly service charges in each rate
class or limit increases in fixed monthly service charges to only partial alignment with
customer costs per customer per month as determined in the cost of service study;

(9) direct UPPCO to provide in its next general rate case a detailed analysis of
customer accounting, sales, and customer service costs and UPPCO’s efforts to control
those costs;

(10) remove reference to a System Access Contribution from the Distributed
Generation tariff.

I also recommend that UPPCO voluntarily, with the Commission’s consent, modify the
Distributed Generation tariff to allow any customer with an on-premise renewable energy
system or methane digester generator and with annual production that does not exceed the
customer’s annual load to receive bill credits for outflow, without restrictions as to
generator size or program participation caps.

Q. Does that complete your testimony?

A. Yes.
# Douglas B. Jester

## Personal Information
Contact Information:
- 115 W Allegan Street, Suite 710
- Lansing, MI 48933
- 517-337-7527
- djester@5lakesenergy.com

## Professional Experience

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<tr>
<th>Position</th>
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<tr>
<td>Partner</td>
<td>5 Lakes Energy</td>
<td>January 2011 – present</td>
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<td>Co-owner of a consulting firm working to advance the clean energy economy in Michigan and beyond. Consulting engagements with foundations, startups, and large mature businesses have included work on public policy, business strategy, market development, technology collaboration, project finance, and export development concerning energy efficiency, smart grid, renewable generation, electric vehicle infrastructure, and utility regulation and rate design. Policy director for renewable energy ballot initiative and Michigan energy legislation advocacy. Supported startup of the Energy Innovation Business Council, a trade association of clean energy businesses. Expert witness in utility regulation cases. Developed integrated resource planning models for use in ten states’ compliance with the Clean Power Plan.</td>
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<td>Business Development Consultant - Smart Grid</td>
<td>Rose International</td>
<td>August 2008 - February 2010</td>
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<td>- Employed by Verizon Business’ exclusive external staffing agency for the purpose of providing business and solution development consultation services to Verizon Business in the areas of Smart Grid services and transportation management services.</td>
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APPENDIX A
pl of 8
December 2007 - March 2010 Efficient Printers Inc

**President/Co-Owner**
- Co-founder and co-owner with Keith Carlson of a corporation formed for the purpose of acquiring J A Thomas Company, a sole proprietorship owned by Keith Carlson. Recognized as Sacramento County (California) 2008 Supplier of the Year and Washoe County (Nevada) Association for Retarded Citizens 2008 Employer of the Year. Business operations discontinued by asset sale to focus on associated printing software services of IT Services Corporation.

August 2007 - present IT Services Corporation

**President/Owner**
- Founder, co-owner, and President of a startup business intended to provide advanced IT consulting services and to acquire or develop managed services in selected niches, currently focused on developing e-commerce solutions for commercial printing with software-as-a-service.

2004 – August 2007 Automated License Systems

**Chief Technology Officer**
- Member of four-person executive team and member of board of directors of a privately-held corporation specializing in automated systems for the sale of hunting and fishing licenses, park campground reservations, and in automated background check systems. Executive responsible for project management, network and data center operations, software and product development. Brought company through mezzanine financing and sold it to Active Networks.

2000 - 2004 WorldCom/MCI

**Director, Government Application Solutions**
- Executive responsible in various combinations for line of business sales, state and local government product marketing, project management, network and data center operations, software and product development, and contact center operations for specialized government process outsourcing business. Principal lines of business were vehicle emissions testing, firearm background checks, automated hunting and fishing license systems, automated appointment scheduling, and managed application hosting services. Also responsible for managing order entry, tracking, and service support systems for numerous large federal telecommunications contracts such as the US Post Office, Federal Aviation Administration, and Navy-Marine Corps Intranet.

- Increased annual line-of-business revenue from $64 million to $93 million, improved EBITDA from approximately 2% to 27%, and retained all customers, in context of corporate scandal and bankruptcy.
- Repeatedly evaluated in top 10% of company executive management on annual performance evaluations.
1999-2000 Compuware Corporation

**Senior Project Manager**
- Senior project manager, on customer site with five project managers and team of approximately 80, to migrate a major dental insurer from a mainframe environment to internet-enabled client-server environment.

1995 - 1999 City of East Lansing, Michigan

**Mayor and Councilmember**
- Elected chief executive of the City of East Lansing, a sophisticated city of 52,000 residents with a council-manager government employing about 350 staff and with an annual budget of about $47 million. Major accomplishments included incorporation of public asset depreciation into budgets with consequent improvements in public facilities and services, complete rewrite and modernization of city charter, greatly intensified cooperation between the City of East Lansing and the East Lansing Public Schools, significant increases in recreational facilities and services, major revisions to housing code, initiation of revision of the City Master Plan, facilitation of the merger of the Capital Area Transportation Authority and Michigan State University bus systems, initiation of a major downtown redevelopment project, City government efficiency improvements, and numerous other policy initiatives. Member of Michigan Municipal League policy committee on Transportation and Environment and principal writer of league policy on these subjects (still substantially unchanged as of 2009).

1995-1999 Michigan Department of Natural Resources

**Chief Information Officer**
- Executive responsibility for end-user computing, data center operations, wide area network, local area network, telephony, public safety radio, videoconferencing, application development and support, Y2K readiness for Departments of Natural Resources and Environmental Quality. Directed staff of about 110. Member of MERIT Affiliates Board and of the Great Lakes Commission’s Great Lakes Information Network (GLIN) Board.

1990-1995 Michigan Department of Natural Resources

**Senior Fisheries Manager**
- Responsible for coordinating management of Michigan’s Great Lakes fisheries worth about $4 billion per year including fish stocking and sport and commercial fishing regulation decisions, fishery monitoring and research programs, information systems development, market and economic analyses, litigation, legislative analysis and negotiation. University relations. Extensive involvement in regulation of steam electric and hydroelectric power plants.
- Served as agency expert on natural resource damage assessment, for all resources and causes.
- Considerable involvement with Great Lakes Fishery Commission, including:
  - Co-chair of Strategic Great Lakes Fishery Management Plan working group
- Member of Lake Erie and Lake St. Clair Committees
- Chair, Council of Lake Committees
- Member, Sea Lamprey Control Advisory Committee
- St Clair and Detroit River Areas of Concern Planning Committees

1989-1990  American Fisheries Society

**Editor, North American Journal of Fisheries Management**

- Full responsibility for publication of one of the premier academic journals in natural resource management.

1984 - 1989  Michigan Department of Natural Resources

**Fisheries Administrator**

- Assistant to Chief of Fisheries, responsible for strategic planning, budgets, personnel management, public relations, market and economic analysis, and information systems. Department of Natural Resources representative to Governor’s Cabinet Council on Economic Development. Extensive involvement in regulation of steam electric and hydroelectric power plants.

1983-present  Michigan State University

**Adjunct Instructor**

- Irregular lecturer in various undergraduate and graduate fisheries and wildlife courses and informal graduate student research advisor in fisheries and wildlife and in parks and recreation marketing.

1977 – 1984  Michigan Department of Natural Resources

**Fisheries Research Biologist**

- Simulation modeling & policy analysis of Great Lakes ecosystems. Development of problem-oriented management records system and “epidemiological” approaches to managing inland fisheries.
- Modeling and valuation of impacts power plants on natural resources and recreation.

**Education**

1991-1995 Michigan State University

**PhD Candidate, Environmental Economics**

Coursework completed, dissertation not pursued due to decision to pursue different career direction.

1980-1981 University of British Columbia

**Non-degree Program, Institute of Animal Resource Ecology**

1974-1977 Virginia Polytechnic Institute & State University

**MS Fisheries and Wildlife Sciences**

**MS Statistics and Operations Research**

1971-1974 New Mexico State University

**BIS Mathematics, Biology, and Fine Arts**
<table>
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<td>Co-organizer, East Lansing Community Unity, 1992-1993</td>
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<td>Bailey Community Association Board, 1993-1995</td>
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<td>East Lansing Street Lighting Advisory Committee, 1994</td>
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<td>Councilmember, City of East Lansing, 1995-1999</td>
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<td>Mayor, City of East Lansing, 1995-1997</td>
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<td>East Lansing Downtown Development Authority Board Member, 1995-1999</td>
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<td>East Lansing Transportation Commission, 1999-2004</td>
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<td>East Lansing Non-Profit Housing and Neighborhood Services Corporation Board Member, 2001-2004</td>
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<td>Lansing – East Lansing Smart Zone Board of Directors, 2007-present</td>
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<td>East Lansing Downtown Development Authority Board Member and Vice-Chair, 2010 – present</td>
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<td>East Lansing Brownfield Authority Board Member and Vice-Chair, 2010 – present</td>
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<td>East Lansing Downtown Management Board and Chair, 2010 – 2016</td>
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<td>East Lansing City Center Condominium Association Board Member, 2015 – present</td>
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Specific Energy-Related Accomplishments

Unrelated to Employment

- Member of Michigan SAVES initial Advisory Board. Michigan SAVES is a financing program for building energy efficiency measures initiated by the State of Michigan Public Service Commission and administered under contract by Public Sector Consultants. Program launched in 2010.
- Member of Michigan Green Jobs Initiative, representing the Council for Labor and Economic Growth.
- Participated in Lansing Board of Water and Light Integrated Resource Planning, leading to their recent completion of a combined cycle natural gas power plant that also provides district heating to downtown Lansing.
- In graduate school, participated in development of database and algorithms for optimal routing of major transmission lines for Virginia Electric Power Company (now part of Dominion Resources).
- Commissioner of the Lansing Board of Water and Light, representing East Lansing. December 2017 – present.

For 5 Lakes Energy

- Participant by invitation in the Michigan Public Service Commission Smart Grid Collaborative, authoring recommendations on data access, application priorities, and electric vehicle integration to the grid.
- Participant by invitation in Michigan Public Service Commission Solar Work Group, including presentations and written comments on value of solar, including energy, capacity, avoided health and environmental damages, hedge value, and ancillary services.
- Participant by invitation in Michigan Senate Energy and Technology Committee stakeholder work group preliminary to introduction of a comprehensive legislative package.
- Participant by invitation in Michigan Public Service Commission PURPA Avoided Cost Technical Advisory Committee.
- Participant by invitation in Michigan Public Service Commission Standby Rate Working Group.
- Participant by invitation in Michigan Public Service Commission Street Lighting Collaborative.
- Participant by invitation in State of Michigan Agency for Energy Technical Advisory Committee on Clean Power Plan implementation.
- Conceived, obtained funding, and developed open access integrated resource planning tools (State Tool for Electricity Emissions Reduction aka STEER) for State compliance with the Clean Power Plan:
  - For Energy Foundation - Michigan and Iowa
  - For Advanced Energy Economy Institute – Arkansas, Florida, Illinois, Ohio, Pennsylvania, Virginia
  - For The Solar Foundation - Georgia and North Carolina
- Expert witness before the Michigan Public Service Commission in various cases, including:
Case U-17473 (Consumers Energy Plant Retirement Securitization)
Case U-17096-R (Indiana Michigan 2013 PSCR Reconciliation)
Case U-17301 (Consumers Energy Renewable Energy Plan 2013 Biennial Review);
Case U-17302 (DTE Energy Renewable Energy Plan 2013 Biennial Review);
Case U-17317 (Consumers Energy 2014 PSCR Plan);
Case U-17319 (DTE Electric 2014 PSCR Plan);
Case U-17674 (WEPCO 2015 PSCR Plan);
Case U-17679 (Indiana-Michigan 2015 PSCR Plan);
Case U-17689 (DTE Electric Cost of Service and Rate Design);
Case U-17688 (Consumers Energy Cost of Service and Rate Design);
Case U-17698 (Indiana-Michigan Cost of Service and Rate Design);
Case U-17762 (DTE Electric Energy Optimization Plan);
Case U-17752 (Consumers Energy Community Solar);
Case U-17735 (Consumers Energy General Rates);
Case U-17767 (DTE General Rates);
Case U-17792 (Consumers Energy Renewable Energy Plan Revision);
Case U-17895 (UPPCO General Rates);
Case U-17911 (UPPCO 2016 PSCR Plan);
Case U-17990 (Consumers Energy General Rates); and
Case U-18014 (DTE General Rates);
Case U-17611-R (UPPCO 2015 PSCR Reconciliation);
Case U-18089 (Alpena Power PURPA Avoided Costs);
Case U-18090 (Consumers Energy PURPA Avoided Costs);
Case U-18091 (DTE PURPA Avoided Costs);
Case U-18092 (Indiana Michigan Electric Power PURPA Avoided Costs);
Case U-18093 (Northern States Power PURPA Avoided Costs);
Case U-18094 (Upper Peninsula Power Company PURPA Avoided Costs);
Case U-18095 (UMERC PURPA Avoided Costs);
Case U-18224 (UMERC Certificate of Necessity);
Case U-18255 (DTE General Rate Case);
Case U-18322 (Consumers Energy General Rate Case).

Expert witness before the Public Utilities Commission of Nevada in
Case 16-07001 (NV Energy 2017-2036 Sierra Pacific Integrated Resource Plan)

Expert witness before the Missouri Public Service Commission in
Case ER-2016-0179 (Ameren Missouri General Rate Case)
Case ER-2016-0285 (KCP&L General Rate Case)
Case ET-2016-0246 (Ameren Missouri EV Policy)

Expert witness before the Kentucky Public Service Commission
Case 2016-00370 (Kentucky Utilities General Rate Case)

Expert witness before the Massachusetts Department of Public Utilities in
Case 17-05 (Eversource General Rate Case)
Case 17-13 (National Grid General Rate Case)

Coauthored “Charge without a Cause: Assessing Utility Demand Charges on Small Customers”

Currently under contract to the Michigan Agency for Energy to develop a Roadmap for CHP Market Development in Michigan, including evaluation of various CHP technologies and applications using STEER Michigan as an integrated resource planning tool.


Under contract to NextEnergy, assisted in development of industrial energy efficiency technology development strategy.
Under contract to a multinational solar photovoltaics company, developed market strategy recommendations.

For an automobile OEM, developed analyses of economic benefits of demand response in vehicle charging and vehicle-to-grid electricity storage solutions.

Under contract to Pew Charitable Trusts, assisted in development of a report of best practices for electric vehicle charging infrastructure.

Under contract to a national foundation, developed renewable energy business case for Michigan including estimates of rate impacts, employment and income effects, health effects, and greenhouse gas emissions effects.

Assisted in Michigan market development for a solar panel manufacturer, clean energy finance company, and industrial energy management systems company.

Under contract to Institute for Energy Innovation, organized legislative learning sessions covering a synopsis of Michigan’s energy uses and supply, energy efficiency, and economic impacts of clean energy.

For Department of Energy Labor and Economic Growth


Drafted analysis and policy paper concerning customer and third-party access to utility meter data.

Analyzed hourly electric utility load demonstrating relationship amongst time of day, daylight, and temperature on loads of residential, commercial, industrial, and public lighting customers. Analysis demonstrated the importance of heating for residential electrical loads and the effects of various energy efficiency measures on load-duration curves.

Analyzed relationship of marginal locational prices to load, demonstrating that traditional assumptions of Integrated Resource Planning are invalid and that there are substantial current opportunities for cost-effective grid-integrated storage for the purpose of price arbitrage as opposed to traditionally considered load arbitrage.

Developed analyses and recommendations concerning the use of feed-in tariffs in Michigan.

Participated in Pluggable Electric Vehicle Task Force and initiated changes in State building code to accommodate installation of vehicle charging equipment.

Organized December 2010 conference on Biomass Waste to Energy technologies and market opportunities.

Participated in and provided support for teams working on developing Michigan businesses involved in renewable energy, storage, and smart grid supply chains.

Developed analyses and recommendations concerning low-income energy assistance coordination with low-income energy efficiency programs and utility payment collection programs.

Drafted State of Michigan response to a US Department of Energy request for information on offshore wind energy technology development opportunities.

Assisted in development of draft performance contracting enabling legislation, since adopted by the State of Michigan.

For Verizon Business

Analyzed several potential new lines of business for potential entry by Verizon's Global Services Systems Integration business unit and recommended entry to the “Smart Grid” market. This recommendation was adopted and became a major corporate initiative.

Provided market analysis and participation in various conferences to aid in positioning Verizon in the “Smart Grid” market. Recommendations are proprietary to Verizon.
Led a task force to identify potential converged solutions for the “Smart Grid” market by integrating Verizon’s current products and selected partners. Established five key partnerships that are the basis for Verizon’s current “Smart Grid” product offerings.

Participated in the “Smart Grid” architecture team sponsored by the corporate Chief Technology Officer with sub-team lead responsibilities in the areas of Software and System Integration and Network and Systems Management. This team established a reference architecture for the company’s “Smart Grid” offerings, identified necessary changes in networks and product offerings, and recommended public policy positions concerning spectrum allocation by the FCC, security standards being developed by the North American Reliability Council, and interoperability standards being developed by the National Institute of Standards and Technology.

Developed product proposals and requirements in the areas of residential energy management, commercial building energy management, advanced metering infrastructure, power distribution monitoring and control, power outage detection and restoration, energy market integration and trading platforms, utility customer portals and notification services, utility contact center voice application enablement, and critical infrastructure physical security.

Lead solution architecture and proposal development for six utilities with solutions encompassing customer portal, advanced metering, outage management, security assessment, distribution automation, and comprehensive “Smart Grid” implementation.

Presented Verizon’s “Smart Grid” capabilities to seventeen utilities.

Presented “Role of Telecommunications Carriers in Smart Grid Implementation” to 2009 Mid-America Regulatory Conference.

Presented “Smart Grid: Transforming the Electricity Supply Chain” to the 2009 World Energy Engineering Conference.

Participant in NASPInet work groups of the North American Energy Reliability Corporation (NERC), developing specifications for a wide-area situational awareness network to facilitate the sharing and analysis of synchrophasor data amongst utilities in order to increase transmission reliability.

Provided technical advice to account team concerning successful proposal to provide network services and information systems support for the California ISO, which coordinates power dispatch and intercompany power sales transactions for the California market.

For Michigan Department of Natural Resources

Determined permit requirements under Section 316 of the Clean Water Act for all steam electric plants currently operating in the State of Michigan.

Case manager and key witness for the State of Michigan in FERC, State court, and Federal court cases concerning economics and environmental impacts of the Ludington Pumped Storage Plant, which is the world’s largest pumped storage plant. A lead negotiator for the State in the ultimate settlement of this issue. The settlement was valued at $127 million in 1995 and included considerations of environmental mitigation, changes in power system dispatch rules, and damages compensation.

Managed FERC license application reviews for the State of Michigan for all hydroelectric projects in Michigan as these came up for reissuance in 1970s and 1980s.

Testified on behalf of the State of Michigan in contested cases before the Federal Energy Regulatory Commission concerning benefit-cost analyses and regulatory issues for four different hydroelectric dams in Michigan.

Reviewed (as regulator) the environmental impacts and benefit-cost analyses of all major steam electric and most hydroelectric plants in the State of Michigan.

Executive responsibility for development, maintenance, and operations of the State of Michigan’s information system for mineral (includes oil and gas) rights leasing, unitization and apportionment, and royalty collection.

In cooperative project with Ontario Ministry of Natural Resources, participated in development of a simulation model of oil field development logistics and environmental impact on Canada’s Arctic slope for Tesoro Oil.
2017 Average Cost per kWh - Industrial

- Hawaii
- Alaska
- Rhode Island
- Massachusetts
- Connecticut
- California
- New Hampshire
- Vermont
- New Jersey
- Maine
- Maryland
- District of Columbia
- South Dakota
- Florida
- Delaware
- Nebraska
- North Dakota
- Kansas
- Indiana
- Colorado
- Wisconsin
- Minnesota
- Missouri
- MICHIGAN
- Ohio
- Wyoming
- Pennsylvania
- Idaho
- West Virginia
- Virginia
- Illinois
- Arizona
- Iowa
- North Carolina
- South Carolina
- Alabama
- Nevada
- New Mexico
- Utah
- Arkansas
- Mississippi
- Oregon
- Georgia
- New York
- Tennessee
- Kentucky
- Louisiana
- Oklahoma
- Texas
- Montana
- Washington

$-
$0.05
$0.10
$0.15
$0.20
$0.25
$0.30
2017 Average Cost per kWh - Michigan Industrial Sector

- Cherryland Electric Coop Inc
- Alger-Delta Coop Electric Assn
- Presque Isle Elec & Gas Coop
- City of Petoskey - (MI)
- City of Grand Haven - (MI)
- City of Bay City - (MI)
- City of Lansing - (MI)
- City of Sturgis
- City of Marshall - (MI)
- Tri-County Electric Coop
- Hillsdale Board of Public Wks
- City of South Haven - (MI)
- City of Holland
- City of Niles - (MI)
- Indiana Michigan Power Co
- Wyandotte Municipal Serv Comm
- Great Lakes Energy Coop
- Consumers Energy Company
- Cloverland Electric Co-op
- City of Escanaba
- Coldwater Board of Public Util
- City of Traverse City - (MI)
- Northern States Power Company
- City of Zeeland - (MI)
- DTE Electric Company
- Upper Peninsula Power Company
- Alpena Power Co
- Wisconsin Electric Power Co

The bar chart shows the 2017 average cost per kWh for various entities in the Michigan industrial sector. The cost ranges from approximately $-0.02 to $0.16. The Upper Peninsula Power Company has the highest cost, indicated by the red bar.
2017 Minutes Outage per Customer excluding Major Event Days

- West Virginia
- Idaho
- Vermont
- Maine
- Mississippi
- Wyoming
- Louisiana
- Michigan
- Arkansas
- Montana
- New Hampshire
- North Carolina
- Ohio
- Virginia
- Oklahoma
- Alaska
- Texas
- Tennessee
- Washington
- Kansas
- Indiana
- Georgia
- Kentucky
- South Carolina
- Alabama
- Utah
- Oregon
- New Mexico
- California
- Pennsylvania
- Hawaii
- Missouri
- Iowa
- Massachusetts
- Nevada
- Maryland
- Delaware
- Florida
- Colorado
- Wisconsin
- South Dakota
- Illinois
- Minnesota
- New York
- New Jersey
- Nebraska
- Connecticut
- North Dakota
- Rhode Island
- District of Columbia
- Arizona
2017 Outages per Michigan Customer including Major Event Days

- Cloverland Electric Co-op
- Midwest Energy Cooperative
- Presque Isle Elec & Gas Coop
- Upper Peninsula Power Company
- City of Grand Haven - (MI)
- Great Lakes Energy Coop
- Indiana Michigan Power Co
- Tri-County Electric Coop
- DTE Electric Company
- Northern States Power Co
- Consumers Energy Co
- Alpena Power Co
- City of Zeeland - (MI)
- City of Lansing - (MI)
- Coldwater Board of Public Util
- Alger-Delta Coop Electric Assn
- City of Marquette - (MI)
- Hillsdale Board of Public Wks
- Cherryland Electric Coop Inc
- City of Bay City - (MI)
- City of Holland
- City of Escanaba
### 2017 Outages per Customer excluding Major Event Days

- Maine
- West Virginia
- Vermont
- Alaska
- Louisiana
- Idaho
- Wyoming
- Mississippi
- New Hampshire
- Arkansas
- Tennessee
- Montana
- Texas
- Hawaii
- Kansas
- Georgia
- Virginia
- Ohio
- North Carolina
- Oklahoma
- South Carolina
- Kentucky
- New Mexico
- Alabama
- Florida
- Indiana
- Delaware
- MICHIGAN
- South Dakota
- Utah
- Washington
- Pennsylvania
- California
- Iowa
- New Jersey
- Colorado
- Oregon
- Maryland
- Missouri
- Nevada
- Rhode Island
- Minnesota
- North Dakota
- Illinois
- Connecticut
- Nebraska
- New York
- Wisconsin
- Massachusetts
- Arizona
- District of Columbia

The chart above illustrates the comparison of outages per customer for each state, excluding major event days, in 2017.
2017 Outages per Customer excluding Major Event Days

- Indiana Michigan Power Co
- Cloverland Electric Co-op
- Presque Isle Elec & Gas Coop
- Great Lakes Energy Coop
- Tri-County Electric Coop
- Upper Peninsula Power Company
- City of Zeeland - (MI)
- DTE Electric Company
- Alger-Delta Coop Electric Assn
- City of Marquette - (MI)
- Consumers Energy Co
- Northern States Power Co
- Alpena Power Co
- City of Lansing - (MI)
- City of Bay City - (MI)
- Cherryland Electric Coop Inc
- City of Holland
- City of Grand Haven - (MI)
2017 Average Minutes to Restore Power to a Customer excluding Major Event Days

- West Virginia
- MICHIGAN
- Massachusetts
- Idaho
- Washington
- Indiana
- Vermont
- Mississippi
- North Carolina
- Oregon
- Ohio
- Wisconsin
- Oklahoma
- Arkansas
- Utah
- Virginia
- California
- Montana
- Wyoming
- Missouri
- New York
- Pennsylvania
- Kansas
- Kentucky
- Maine
- Nevada
- Alabama
- Louisiana
- South Carolina
- Iowa
- Texas
- District of Columbia
- Nebraska
- Georgia
- New Mexico
- Connecticut
- Maryland
- New Hampshire
- Illinois
- Minnesota
- Tennessee
- Arizona
- Colorado
- Hawaii
- North Dakota
- Delaware
- New Jersey
- South Dakota
- Rhode Island
- Florida
- Alaska
Metric Tons Sulfur Dioxide Emissions per Gigawatt-hour Electricity Generated in 2016

- Hawaii
- Nebraska
- Missouri
- North Dakota
- Ohio
- Kentucky
- Arkansas
- MICHIGAN (red)
- Indiana
- Wyoming
- Maryland
- Oklahoma
- Tennessee
- Maine
- Iowa
- West Virginia
- Louisiana
- Illinois
- Texas
- Alaska
- Pennsylvania
- Wisconsin
- Minnesota
- Montana
- Georgia
- North Carolina
- Alabama
- Colorado
- Utah
- Virginia
- Florida
- Idaho
- South Carolina
- New Mexico
- Mississippi
- New York
- Kansas
- Oregon
- Arizona
- Massachusetts
- Washington
- District of Columbia
- South Dakota
- Nevada
- Delaware
- New Hampshire
- New Jersey
- Vermont
- Connecticut
- Rhode Island
- California
Metric Tons Nitrogen Oxide Emissions per Gigawatt-hour Electricity Generated in 2016

- District of Columbia
- Alaska
- Hawaii
- New Mexico
- North Dakota
- Indiana
- Utah
- Wyoming
- Missouri
- Kentucky
- West Virginia
- Louisiana
- Montana
- Nebraska
- Ohio
- Colorado
- Maine
- Arkansas
- Iowa
- MICHIGAN
- Wisconsin
- Minnesota
- Pennsylvania
- North Carolina
- Texas
- Kansas
- Maryland
- California
- Oklahoma
- Virginia
- Arizona
- Massachusetts
- Georgia
- Vermont
- Idaho
- Florida
- Tennessee
- Nevada
- Alabama
- New York
- Mississippi
- Delaware
- Oregon
- Illinois
- Connecticut
- South Carolina
- New Jersey
- Rhode Island
- Washington
- New Hampshire
- South Dakota
Upper Peninsula Power Company
MPSC Case No. U-20276
2019 Rate Case

Upper Peninsula Power Company’s Responses to
CARE’s
First Discovery Request

1-CARE-UPPCO-010

Reference testimony of Gradon Haehnel, page 25 lines 19-23. Provide the working model of the
cost of service study as offered in this testimony.

UPPCO Response

Please find attached, Confidential “UPPCO COS 2019 wo MS_FINAL_FINAL Protected.xlsx” in
response to this question.

Response by: Gradon R. Haehnel, Director of Regulatory Affairs

Dated: November 9, 2018
Cost of New Entry PY 2019/20

Resource Adequacy Subcommittee

12 September 2018
Overview

• Purpose
  ▪ Present summary of updated efforts on locational cost of new entry (‘CONE’) values

• Key takeaways
  ▪ FERC filing made on 5 September 2018 for estimates of MISO’s locational CONE values for planning year 2019/2020
  ▪ MISO’s estimates are down on last year’s estimates systematically across all LRZs.
Sections

• Introduction
• Inputs
• Methodology
• Results
Introduction

- Cost of New Entry (CONE) is an industry-wide term, used to indicate the current, annualised, capital cost of constructing a power plant.
  - The plant is assumed to be used infrequently.
  - The calculations made by various entities use differing assumptions and methods.
- CONE is used by MISO primarily as the maximum offer and maximum clearing price, converted to a daily value, in the Planning Resource Auctions.
- Net CONE is a related concept, wherein expected inframarginal rents from energy & ancillary services are subtracted from the CONE value.
  - Not currently in use at MISO
Inputs

• Primary Inputs
  ▪ Economic
    ◦ Implicit price deflator
    ◦ O&M escalation factor (2%)
  ▪ Financial
    ◦ 55/45 debt/equity ratio
    ◦ 20-year project/finance life
    ◦ 5.78% cost of debt
    ◦ 13.4% after tax return on equity
    ◦ 26.7% effective tax rate
  ▪ Capital Costs, by Local Resource Zone (EIA)
    ◦ See filing, Attachment A
  ▪ Operation & Maintenance Costs (EIA)
    • See MISO’s 5 September 2018 filing for details.
Methodology

• Capital costs annualised using net present value (NPV) method

• O&M costs escalated, then annualised using NPV

• Insurance & property taxes are add-on costs
  ▪ 1.5% of the capital costs

• Results checked against IMM calculations
### Results

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<th>ZONE</th>
<th>PY 2019/20 CONE $\text{MW} \cdot \text{yr}^{-1}</th>
<th>$</th>
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questions?

• contact

Michael Robinson (mrobinson@misoenergy.org)
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<th>Line No.</th>
<th>Rate Class</th>
<th>Present Revenue as Filed COSS</th>
<th>Revenue Deficiency as Filed COSS</th>
<th>Revenue Responsibility as Filed COSS</th>
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<th>Revenue Responsibility 20:80 Production Plant Allocator</th>
<th>Change in Revenue Responsibility</th>
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<td>U-17564 Credit at $2,584,802/yr</td>
<td>U-17564 Credit at $4,333,333/yr</td>
<td>% of Distribution and Transition Credit Customer Costs $694,563/yr</td>
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<td>TOTAL</td>
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<td>Rate Class</td>
<td>Present Revenue as Filed COSS</td>
<td>Revenue Responsibility 20:80 Production Plant Allocator</td>
<td>U-17564 Credit at $4,333,333/yr</td>
<td>Pension &amp; Transition Credit $694,563/yr</td>
<td>Net Revenue Requirement (d) + (e) + (f)</td>
<td>Net Increase/ (Decrease) (g) - (c)</td>
</tr>
<tr>
<td>----------</td>
<td>------------------</td>
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<td>$(44,946)</td>
<td>$5,800,117</td>
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<td>$(70,658)</td>
<td>$10,340,209</td>
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<td>$(7,854)</td>
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<td>$198,752</td>
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<td>$16,628,263</td>
<td>$(735,557)</td>
<td>$(100,645)</td>
<td>$15,792,062</td>
<td>$4,611,505</td>
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<td>Cp-U Secondary</td>
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<td>$6,964,304</td>
<td>$(260,860)</td>
<td>$(36,892)</td>
<td>$6,666,552</td>
<td>$2,239,545</td>
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<td>Cp-U Primary</td>
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<td>$(28,304)</td>
<td>$(3,888)</td>
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<td>Cp-U Transmission</td>
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<td>$(5,805)</td>
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<td>$(6,740)</td>
<td>$779,479</td>
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<td>$(41,313)</td>
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<td>$(857)</td>
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<td>$24,915</td>
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<tr>
<td>18</td>
<td>TOTAL</td>
<td>$91,120,789</td>
<td>$104,382,758</td>
<td>$(4,333,333)</td>
<td>$(694,563)</td>
<td>$99,354,862</td>
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</table>
Upper Peninsula Power Company’s Responses to CARE’s First Discovery Request

1-CARE-UPPCO-001

Reference testimony of James C. Larsen, page 6 lines 6-7. Please explain how the “mechanics of these changes” have affected “larger usage customers” differently than other customers. Provide a table showing the cumulative effect of these changes by rate class.

UPPCO Response

Although there have been several changes, most of the reductions since the last rate case in 2016 resulted in reductions on a volumetric basis. As a result, the mechanics of the changes have resulted in greater reductions for customers who used more energy. Here is a table showing the cumulative effect of the rate changes by class from the outcome of the last rate case until today.

<table>
<thead>
<tr>
<th>Customer Class</th>
<th>Oct-2016</th>
<th>Nov-2018</th>
<th>Reduction in Bill</th>
</tr>
</thead>
<tbody>
<tr>
<td>A-1</td>
<td>$121</td>
<td>$106</td>
<td>-13%</td>
</tr>
<tr>
<td>A-2</td>
<td>$116</td>
<td>$100</td>
<td>-13%</td>
</tr>
<tr>
<td>AH-1</td>
<td>$161</td>
<td>$130</td>
<td>-19%</td>
</tr>
<tr>
<td>C-1</td>
<td>$844</td>
<td>$642</td>
<td>-24%</td>
</tr>
<tr>
<td>H-1</td>
<td>$668</td>
<td>$491</td>
<td>-27%</td>
</tr>
<tr>
<td>P-1</td>
<td>$2,778</td>
<td>$2,080</td>
<td>-25%</td>
</tr>
<tr>
<td>CP-U (Trans) (Firm)</td>
<td>$115,649</td>
<td>$88,722</td>
<td>-23%</td>
</tr>
<tr>
<td>CP-U (AES) (Interruptible)</td>
<td>$9,445</td>
<td>$958</td>
<td>-90%</td>
</tr>
<tr>
<td>WP-3 (Firm)</td>
<td>$349,184</td>
<td>$271,549</td>
<td>-22%</td>
</tr>
<tr>
<td>WP-3 (AES) (Interruptible)</td>
<td>$13,470</td>
<td>$12,527</td>
<td>-7%</td>
</tr>
<tr>
<td><strong>Average Reduction in Bill</strong></td>
<td><strong>$13,470</strong></td>
<td><strong>$12,527</strong></td>
<td><strong>-26%</strong></td>
</tr>
</tbody>
</table>

Response by: James C. Larsen, CEO

Dated: November 9, 2018