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December 12, 2025

VIA ELECTRONIC CASE FILING

Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway
Lansing, Michigan 48917

Re: ***Case No. U-21870 – In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief.***

Dear Executive Secretary:

Enclosed for filing please find the ***Association of Businesses Advocating Tariff Equity's*** ***Corrected*** ***Initial Brief*** and ***Proof of Service*** in the above-referenced proceeding.

Please note – this correction merely moves the references to the record from footnotes to the body of the brief

Sincerely,

CLARK HILL PLC

Stephen A. Campbell

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SAC/lkd

cc: Parties of Record

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870 ALJ Jonathan F. Thoits

CORRECTED INITIAL BRIEF OF THE ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

The Association of Businesses Advocating Tariff Equity ("ABATE"), by its attorneys, CLARK HILL PLC, files its Initial Brief in this proceeding initiated by Consumers Energy Company ("Consumers" or the "Company") before the Michigan Public Service Commission ("Commission") in accordance with the schedule established by the presiding Administrative Law Judge ("ALJ").

TABLE OF CONTENTS

I. INTRODUCTION

The Commission may authorize a Michigan utility to collect rates and charges that are just and reasonable considering the utility's reasonable cost of doing business. In requesting Commission approval, the applicant utility or moving party bears the burden of demonstrating that its proposals are reasonable and prudent. Despite this requirement, Consumers and certain intervenors put forth several proposals in this proceeding which would result in rates that do not meet this standard and should be rejected or modified.

These proposals include the Company's use of a projected test year which inflates Consumers' revenue requirement using conjectural expenses which do not reflect actual costs. Further, numerous capital expenditure proposals are not adequately supported such that cost recovery is unreasonable at this time. In addition, the Company's requested return on equity ("ROE") and equity ratio are excessive, inadequately supported, and unnecessary, and its projected operations and maintenance ("O&M") costs are inflated and unreasonable. The Company's proposal to significantly expand its new investment recovery mechanism ("IRM") is also imprudent at this time and should be rejected. In addition, intervenor proposals to reject a facilities allowance for Rate LED, limit the permissible contract term for those customers, and dramatically alter the Company's cost allocation such that costs are allocated to customers which do not cause them are unsupported, unreasonable, and should be rejected.

Accordingly, to ensure just and reasonable rates the Commission should adopt the recommendations set out below. These proposals will ensure Consumers' rates are reasonable and prudent and properly collected from the customers which cause them.

II. ARGUMENT

A. Test Year –The Commission should base the Company's revenue requirement on its historic test year where the Company has not adequately supported its projections.[1]

References in the Record: Myers 2 Tr 1360-63 (supporting the Company's proposal); Dauphinais 6 Tr 3639-44 (objecting to the use of a projected test year).

Less than one year ago the Company received a $175.6 million revenue increase in Case No. U-21585. Despite that extraordinary increase, two months later the Company requested an additional $460.2 million revenue increase while its actual revenue and cost data for the Company's historical test year clearly demonstrated a revenue deficiency of only $2 million. (Consumers Application at 2; Exhibit A-1.) These consistent annual requests for hundreds of millions of dollars of additional revenue are driven by the Company's approach of seeking rate increases based on projected future costs, rather than those it has actually incurred. Given these endless and exorbitant requests the Commission should be vigilant in ensuring the Company's cost projections are adequately supported and should base Consumers' revenue requirement on historic costs where the Company does not meet that burden.

As set out in MCL 460.6a(1) a utility "may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges." Despite this permissive statutory language, however, a Commission Order approving such a proposal must be reasonable, meaning it is supported by competent, material, and substantial evidence. MCL 462.26(8); *Attorney General v Mich Pub Serv Comm*, 249 Mich App 424, 429 (2002). For instance, the Legislature's treatment of projected test years "reflects its understanding that the PSC would reject a test year set so far removed from circumstances actually in view as to render it less than

[1] ~~This issue is addressed at Myers 2 Tr 1360-63 (supporting the Company's proposal); Dauphinais 6 Tr 3639-44 (objecting to the use of a projected test year).~~

workable, or that, should the PSC adopt such a flawed test year, it would be subject to appellate challenges for unreasonableness." *In re Application of Consumers Energy Co*, 338 Mich App 239, 247 (2021); see also *In re DTE Electric Co*, unpublished per curiam opinion of the Court of Appeals, issued February 25, 2021 (Docket Nos. 349924, 350008), p 11[2] (stating that "a utility that selects a test year set too far in the past or future would obviously risk rejection by the PSC, and doing so would likely make adjustments prohibitively difficult" and "[a]ny adoption by the PSC of such an inappropriate test year would also be subject to appellate challenges for unreasonableness").

As the Commission has also explained, where a utility decides to base its filing on a fully projected test year, the utility bears the burden to substantiate its projections. *In re Detroit Edison*, order of the Public Service Commission, entered January 10, 2011 (Case No. U-15768), p 9. Utilities must include all evidence (or sources of evidence) in support of their test year projections in their initial rate case filings. *Id*. If the utility does not provide sufficient support for a particular revenue or expense item (particularly for an item that substantially deviates from the historical data), "the Commission may choose an alternative method for determining the projection." *Id*. As set out further below the Company has done so with regard to a number of requested cost recovery proposals here. As such, with regard to those proposals the Commission should utilize the alternative method of using historical test year amounts adjusted for only known and measurable changes.

As the Commission has stated previously, the "Commission's expectation is that the parties will fully document the basis for their test year projections by offering into evidence detailed supporting explanations and underlying assumptions rooted in expected business, financial, and

[2] Also available at Case No. U-20162 Filing No. U-20162-0643 (February 25, 2021).

economic circumstances," and "[r]ate applications may not rely on undocumented estimates of future ratemaking expenses and revenue criteria." *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered May 8, 2020 (Case No. U-20561), p 13. "The record thus created should lend itself to a comparative review of the reasonableness and prudence of the projections" and "[h]istorical data may play a role" and may be the controlling factor "in circumstances that clearly demonstrate that it is a more fair and reasonable reflection of the utility's cost of service, relative to projected data." *Id*. In other words, the Commission is not required to base utility rates on projected costs and may instead utilize historic data when it is a more fair and reasonable indication of the utility's costs. The Commission should do so here where the Company has not adequately supported its cost projections.

The fundamental flaw presented by basing utility revenues on hypothetical and potential future costs has been expounded upon at length by numerous entities which regularly participate in these proceedings. In response to the Commission's own request that parties provide information on whether the fully projected test year serves the best interests of utility customers, numerous entities representing myriad interests have explained in no uncertain terms that it does not. (See Case No. U-21637, ABATE Reply Comments at 11-14.) As explained by the Natural Resources Defense Council, Ecology Center, EcoWorks, Legacy & love, LLC, Michigan Environmental Council, Michigan Environmental Justice Coalition, Michigan League of Conservation Voters, Sierra Club, Sistas in Development, LLC, Soulardarity, Urban Core Collective, and We Want It Green, Too (collectively "NRDC"), "[c]laimed revenue deficiencies are often grossly inflated" and "[p]rojected test years compound the issue by exacerbating information asymmetry problems inherent in ratemaking and increasing the likelihood that Commission directives will slip through the cracks across multiple rate cases," as "[f]orecasts are

prone to bias and manipulation and can further obscure inefficiencies and imprudently incurred costs." (See Case No. U-21637, NRDC Comments at 4-5, 12-13.) The Attorney General similarly explained that "[p]rojected test years have been very beneficial to utilities to the detriment of customers who have paid higher rates as a result," as a "fully projected test year relies too heavily on unknown and forecasted information that often the utility has not fully developed." (See Case No. U-21637, Attorney General Comments at 9.) The Michigan Office of Administrative Hearings and Rules ("MOAHR") itself confirmed that "[w]here utility projections are often unchallenged and result in substantial rate increases, a fully projected test year may not serve the best interests of utility customers." (See Case No. U-21637, MOAHR Comments at 3.) The Company's use of projected test year costs as the basis for its requested revenue increases has embodied all of these flaws and the cost recovery proposals discussed below demonstrate they are present in this case as well.

Indeed, it is beyond dispute that setting the Company's revenue levels based on projected and potential future costs consistently results in excessive cost recovery. For instance, in its six most recent general rate cases the Company's projected revenue deficiency has far exceed its actual historical test-year revenue deficiencies and, more alarmingly, sufficiencies (Dauphinais 6 Tr 3639-44):

TABLE JRD-3

Historic Test Year and Projected Test Year

Rate Sufficiency / (Deficiency)

Case	Historical Test Year Sufficiency / (Deficiency)	Projected Test Year Sufficiency / (Deficiency)	Difference Between Historical and Projected
U-17990	$13,967,000	($225,413,000)	($239,380,000)
U-18322	$26,118,000	($172,758,000)	($198,876,000)
U-20134	$17,354,000	($57,900,000)	($75,254,000)
U-20697	$21,835,000	($244,357,000)	($266,192,000)
U-20963	$25,071,000	($225,102,000)	($250,173,000)
U-21224	($83,384,000)	($266,442,000)	($183,058,000)
U-21389	($99,164,000)	($207,084,000)	($107,920,000)
U-21585	($47,985,000)	($302,579,000)	($254,594,000)
U-21870	($2,033,000)	($435,881,000)	($433,848,000)
Total	($128,221,000)	($2,137,516,000)	($2,009,295,000)

Sources:
Case No. U-17990, Exhibit A-1 and Exhibit A-6, Schedule A-1
Case No. U-18322, Exhibit A-1 and Exhibit A-6, Schedule A-1
Case No. U-20134, Exhibit A-1 and Exhibit A-11, Schedule A-1
Case No. U-20697, Exhibit A-1 and Exhibit A-11, Schedule A-1
Case No. U-20963, Exhibit A-1 and Exhibit A-11, Schedule A-1
Case No. U-21224, Exhibit A-1 and Exhibit A-11, Schedule A-1
Case No. U-21389, Exhibit A-1 and Exhibit A-11, Schedule A-1
Case No. U-21585, Exhibit A-1 and Exhibit A-11, Schedule A-1
Case No. U-21870, Exhibit A-1 and Exhibit A-11, Schedule A-1

In other words, using Consumers' own numbers it would not have been able to seek the exorbitant rate increases it has routinely requested if it had been required to base its revenues on its historic costs. (*Id.*) This is particularly evidenced by the Company reporting a revenue *sufficiency* of $13 to $26 million for its historical test year in five of its most recent rate case filings. In other words, *the Company received $13 to $26 million more than it required to earn its authorized rate of return* in five of its most recent rate case filings. Thus, in these historic test years Consumers' rates were ultimately more generous than necessary to provide the Company a reasonable opportunity to earn its authorized return. Furthermore, these values reflect Consumers'

reported historic test year values which, if more closely examined, might very well reveal costs that are not recoverable in rates. (*Id*.) Consumers' actual revenues in excess of its authorized rate of return in its historic test years therefore may very well have been well in excess of the amount it reported. The use of projected costs to establish the Company's revenue requirement is therefore a vehicle for excessive rates and unnecessarily inflated revenue recovery. The Commission must consider this context when evaluating the Company's cost recovery proposals, particularly those discussed further below.

The Company itself effectively acknowledged this issue, stating that "[i]f spending is only reviewed after the fact and only then determined to be an item that should be disallowed from rates, it can lead to write-offs for the Company and an inefficient use of a finite amount of dollars available to invest in the system." (Myers 2 Tr 1362.) In other words, the use of projected test years to establish revenue requirements entails cost recovery which may not have been appropriate. While Consumers apparently considers such excessive revenue recovery appropriate, the point that this argument entirely elides is that *Consumers should not recover costs for unreasonable and imprudent expenditures*. In contrast to this basic principle of establishing just and reasonable rates, the Company has asserted that it is more efficient for the Company to receive rate revenue for items which ultimately "should be disallowed from rates," than for the Commission to review the reasonableness and prudence of the Company's actual expenditures. This turns the entire paradigm of regulating utility rates on its head and prioritizes utility revenue collection over the establishment of accurate and reasonable customer rates.

Establishing revenue levels based on projected test years therefore allows Consumers to begin recovering costs before they have been verified as real and prudently incurred, which has

significant detrimental impacts on ratepayers.[3] The most important of these impacts is that customers experience excessive rate increases earlier than if the Company had used historical test years to establish its revenue. (Dauphinais 6 Tr 3639-44.) Further, projected test years eliminate the Company's incentive to contain costs that would otherwise exist due to regulatory lag, meaning they effectively cushion the Company's spending and reduce the Company's risk at ratepayer expense.[4] (*Id*.) As noted above, Consumers effectively acknowledged this reality. In addition, they permit the Company to include proposed expenditures in its projections which it has not committed to incurring and can avoid to improve its shareholders' rate of return. (*Id*.)

As demonstrated by its historic revenue sufficiencies, projected test years have allowed Consumers to recover costs for ultimately unnecessary capital expenditures which it was not possible for Staff or other intervenors to identify during the Company's applicable rate case. (*Id*.) This last reality is effectively unavoidable when the Company uses a projected test year as part of its rate case filing; i.e., Staff and intervenors are tasked with an exacting review of the Company's voluminous application, testimony, and exhibits to ensure projected capital expenditures are reasonable. (*Id*.) This asks significantly more from stakeholders and customers than would be

[3] The Company's assertions that "[t]his is the most accurate way to set rates and . . . provides Intervenors with an opportunity to comment on the Company's plans for spending prior to the dollars being spent" are inaccurate and demonstrate the fundamental problem with projected test years. (Myers 2 Tr 1361.) As noted above the use of projected costs as the basis for establishing utility revenues has consistently resulted in misalignment between costs and revenues to the detriment of ratepayers. The "opportunity to comment on the Company's plans for spending" is entirely inadequate, as the Commission effectively acknowledged in opening Case No. U-21637 for discussion on this issue.

[4] Despite the Company's claim, the issue with this reality is not that "[o]nce rates are established, the Company is left to manage the business within those rates," it is instead that the Company's rate case filings and revenue requests continue to expand so that adequate review becomes increasingly challenging, and the level at which rates are established in the first place is demonstrably and consistently above what the Company actually requires to manage its business. (Myers 2 Tr 1362.)

required if requested revenue increases were based on historical test years, particularly as rate case schedules are truncated and utility proceedings continue to overlap. In other words, given practical procedural realities, the use of projected test years will necessarily result in interested parties missing or failing to adequately challenge unreasonable and inappropriate cost projections which will ultimately be collected from customers. (*Id*.) These projected expenditures are not known and measurable; they are instead highly speculative and potentially avoidable. As noted above this point has been recognized by numerous entities, including the MOAHR.

This approach and its result, stemming from Consumers' consistent inability to accurately project costs and revenues in a projected test year, is inconsistent with the Commission's responsibility to approve rates that are just and reasonable. See *Ass'n of Businesses Advocating Tariff Equity v Pub Serv Comm*, 208 Mich App 248, 259 (1994) ("Once the PSC's ratemaking authority is invoked [] the PSC may look at all relevant factors in exercising its broad discretion to determine a just and reasonable rate"); *Attorney General v Pub Serv Comm*, 189 Mich App 138, 146 (1991) (explaining "it is well settled that the universal test of the lawfulness of utility rates is that the rates be 'just and reasonable'"). The Commission should therefore carefully analyze the Company's support for its projections (particularly those discussed below) and, where Consumers fails to demonstrate costs are certain to be incurred, and that cost recovery is reasonable and prudent, establish the Company's revenue requirement using its historic costs.

Specifically, the Commission should ensure Consumers' is irrevocably committed to making the investments it projects it will incur, and that those investments are precisely quantified with respect to both the amount and the specific quarter in which Consumers will incur them. This level of specificity and detail are necessary to hold the Company accountable to its projections, and Consumers' requests that customers continue to pay hundreds of millions of dollars in

additional costs each year for those projections. The drop in Consumers' historical test year revenue deficiency in this proceeding to only approximately $2 million dollars is concerning and does not indicate the Company's projections are sufficiently supported or accurate. To ensure the Company does not collect revenues in excess of the costs it actually eventually incurs the Commission must hold the Company to its burden and establish a revenue requirement based on historical costs where Consumers fails to meet the same.

B. Rate Base - Cost recovery for numerous proposed capital expenditures was not adequately supported and should be rejected.

When evaluating Consumers' requested revenues for capital expenditures, it is important to consider the effectiveness of the Company's use of its capital expenditure revenue and its overall system performance. Such an analysis demonstrates that the Company's service reliability is consistently poor relative to its peer utilities, particularly considering the significant and consistent requests for revenue increases described above.

First, the Utility Distribution Audit of Consumers Energy prepared by the Liberty Consulting Group and filed in Case No. U-21305 on September 23, 2024 ("Audit") noted that the Company's SAIDI and CAIDI metrics for 2022 and 2023 were in the 4th quartile, including MEDs, and the 3rd quartile, excluding MEDs. (Audit Part I at 71.) Comparing Consumers' SAIDI with MEDs (All Days) and SAIDI without MEDs (No MEDs) to other investor-owned utilities in Michigan and states sharing a land border with Michigan (Ohio, Indiana, and Wisconsin) for 2020-2024 similarly demonstrates that of the 17 utilities represented, Consumers ranks between 12 and 17, depending on the metric and year, with an average rank of about 15 out of 17. (Fitzhenry 6 Tr 3713-19.) In other words, compared its peer utilities over the last five years Consumers' reliability performance ranks near the bottom. In addition, the average SAIDI with MEDs for all utilities for the past five years has been approximately 322 minutes per year, while Consumers

SAIDI with MEDs average was approximately 661 minutes per year, meaning the average Consumers' customer experienced approximately 339 minutes more of outages per year than the average Investor Owned Utility customer in Michigan, Indiana, Wisconsin, and Ohio. (*Id.*)

Consumers' outages were overwhelming the result of trees or trees outside the ROW (52%) and weather (26%) (*Id.*):

Table CTF-2

Primary Cause of Outages (2022-2024)

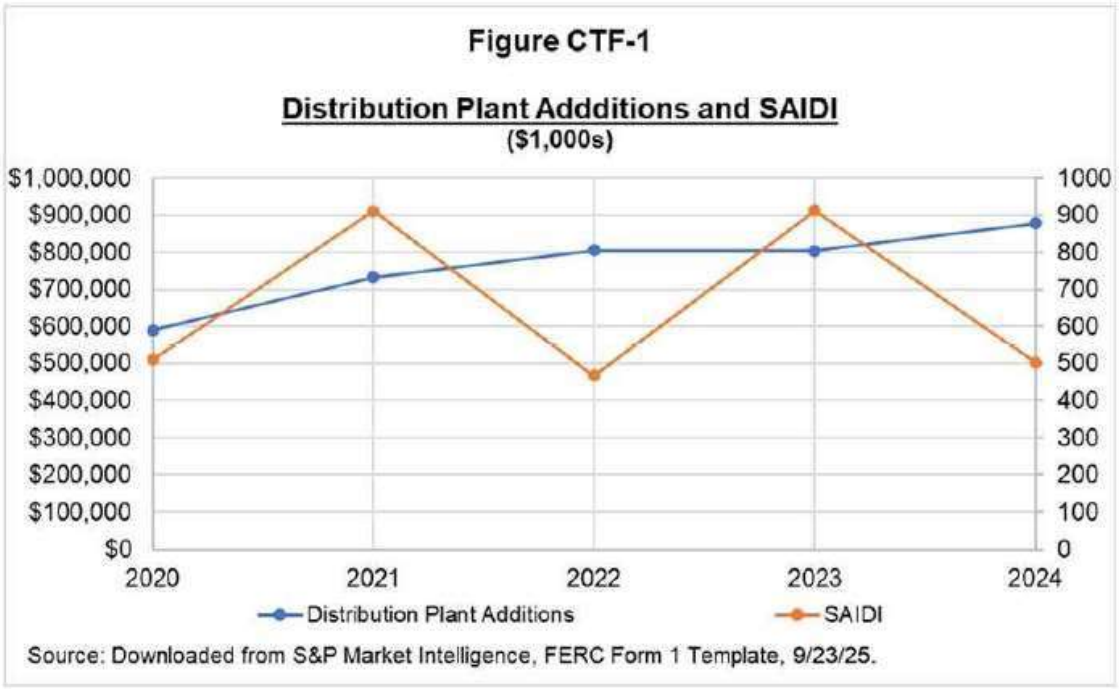
Line	Outage Cause	Customer Minutes Interrupted	Percent of Total
1	No Specific Cause Found	188,416,635	5%
2	Unique Incident	57,626,749	1%
3	Animal	29,634,390	1%
4	Equipment Failure	358,224,514	9%
5	Trees	1,839,800,787	45%
6	Weather	1,073,280,202	26%
7	Bird	7,097,739	0%
8	Public Damage	21,484,876	1%
9	Public Tree Trimming	3,715,716	0%
10	Lightning	31,731,784	1%
11	Trees - Outside ROW	285,112,117	7%
12	Forced Outage/Emergency	21,042,345	1%
13	Car/Pole Accident	147,201,874	4%
14	Transmission/Generation	16,078,517	0%
15	Total	4,080,448,245	100%

Source: U21870-AB-CE-0700_Kelly_ATT_1.xlsx provided in response to Data Request U21870-AB-CE-0700.

As noted above, only 22% of outages were the result of other causes such as equipment failures, car/pole accidents, unique incidents, etc. As equipment failures only account for a small percentage of total outage minutes, meaningful improvement in the Company's future reliability metrics should therefore focus on vegetation management, as opposed to asset replacement.[5]

[5] The Company's assertion that the full benefits of line clearing may take time to materialize is not a justification for dramatically increasing spending for a less effective capital investment approach which has had little impact on the Company's SAIDI metrics. (Kelly 2 Tr 957, 1144-47.) Indeed the Company's claim that "[t]rees are living organisms that are always changing" and a "tree that

Despite this relationship, the Company has requested significant capital cost recovery in this proceeding, continuing a trend evident in its past rate cases. Despite these investments, system performance has improved little over the past five years (*Id.*):



As demonstrated in the graph above, the Company's capital expenditures for distribution plant additions increased approximately $287 million (49%) between 2020 and 2024 without any discernable improvement trend in the Company's SAIDI with MEDs metric. (*Id.*) In other words, Consumers has continued to expend (and recover) vast amounts for distribution capital expenditures without meaningfully reducing customer outage minutes over the last five years.

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poses no threat today may become a hazard before the next clearing cycle" is an argument for focusing efforts on this approach. (Kelly 2 Tr 957.) It's claim that "weather impacts on the system can cause direct damage to assets even if trees are not involved" is unsupported by any detail regarding the percentage of outages caused by such incidents, if they occurred at all, and acknowledges that even outages which result from "failed assets that have not been hardened" are tree-related. (Kelly 2 Tr 1146.) In other words, the Company's objection to focusing its efforts on vegetation management are based on speculation rather than any evidenced justification for expending more on capital projects.

While it hasn't had a material impact on system performance, this distribution system investment has had a significant impact on overall rate base; Consumers' requested $15 billion rate base in this proceeding is $3.7 billion more than the rate base approved in Case No. U-20697 ($11.7 billion) for the 2021 test year. (*Id*.) In other words, while the Company has not demonstrated its continued and significant distribution capital expenditure increases have any meaningful impact on customer outages, its rate base increase from new infrastructure investments continues to be a primary driver of its revenue requirement and rate increases.

The Commission itself has previously expressed its concern with this approach. *In the Matter of the Application of Consumers Energy Co*, order of the Public Service Commission, entered March 21, 2025 (Case No. U-21585), pp 20-22. In Consumers' last rate case, the Commission acknowledged "the concerns of intervenors, as the ALJ captured," including "the concern over the difference of increased spending for capital projects of 44% to improve reliability in this case while spending projections for the proven and cost-effective method of tree trimming remains relatively flat." *Id*. The Commission found "these spending projections to be incongruous" and encouraged Consumers "to heed this noted concern." *Id*. Indeed, the Commission cited to numerous past rate cases and reiterated that "[u]tility capitalization policies are an ongoing concern for the Commission which warrants further investigation." *Id*. (internal citations omitted). Specifically, the Commission again noted "its concern with the disproportionate increase to capital projects over potentially more cost-effective O&M expenditures, as well as ongoing questions over whether certain cost categories have been appropriately classified as capital." *Id*. Rather than heed this concern, as requested by the Commission, the Company has again here proposed significant increases in cost recovery for capital projects with minimal demonstrated service improvements.

The Company's approach therefore continues a troubling and unreasonable pattern of significantly increasing rates for distribution capital investment with no corresponding improvement in reliability. The Company's claim that reliability is improving is based on a curated perspective of its data, selectively focusing on SAIDI excluding MEDs,[6] while ignoring the more critical all-weather SAIDI metric that reflects the actual experiences of its customers. (Kelly 2 Tr 947-50, 1144-50.) The Company's claim that SAIDI excluding MEDs is a valid metric does not demonstrate it is appropriate in isolation. (*Id.*) Indeed, while the Company claimed the Commission requires annual performance information related to SAIDI without MEDS, it also requires performance information related to SAIDI with MEDs. (Kelly 2 Tr 1028, 1147-48.) As noted above, while the Company claims its SAIDI performance without MEDs is improving, a comparative view demonstrates that it consistently ranks below the majority of its peers. Again, the average Consumers customer experiences an unacceptable 339 minutes of outages per year more than the average customer of other electric utilities both within Michigan and in neighboring states. (Fitzhenry 6 Tr 3713-19.) The Company acknowledged that these figures "do speak for themselves to some extent." (Kelly 2 Tr 1144-45.)

This inadequate performance has persisted and has not been meaningfully improved despite a massive influx of capital. While the Company's distribution plant additions have increased by 49% ($287 million) over the past five years, there has been no meaningful reliability gains for customers. The Company's acknowledgement that its "argument is not that its reliability is good relative to peers today" and is "even now in the third quartile" demonstrates the unreasonableness of its requests. (*Id.*) To the extent it has demonstrated any SAIDI improvement

[6] Indeed, the Company explicitly stated its "strategy specifically targets SAIDI excluding MEDs." (Kelly 2 Tr 1148.)

at all (which, as set out above, it has not when reviewing appropriate SAIDI metric data), it does not justify the extraordinary revenue increase the Company has requested.

The Company should therefore focus investment on the primary cause of outages, as opposed to capital investments which grow future returns without demonstrable benefits in customer service. The Commission should therefore review the Company's capital expenditure proposals with extreme skepticism. Continually approving tens and hundreds of millions of dollars of capital expenditures which do not improve service reliability is neither reasonable or prudent; customers should not continually bear the cost of billions of dollars in new investment while receiving little tangible benefits in return. For Consumers to meet its burden to demonstrate that its investment and cost recovery proposals are reasonable and prudent, the Commission should therefore require that the Company demonstrate a clear link between its investments and quantifiable reliability improvements. Without such a demonstration the Commission should reject the Company's proposed cost recovery and rate increases related to capital expenditures. Here, considering the clear historical lack of efficacy in Consumers' prior investment decisions, the Commission should reduce the Company's proposed distribution capital investments as set out below.

1. Distribution capital expenditures.

a. HVD capital expenditures.[7]

References in the Record: Hayward 2 Tr 737-75, 904-11, 916-19; Kelly 2 Tr 1052-58, 1130-32, 1142, 1151-53 (recommending the Commission approve the Company's proposal); Coppola 2 Tr 1935-48; Fitzhenry 6 Tr 3734-35; Schiller 6

[7] ~~This issue is addressed at Hayward 2 Tr 737-75, 904-11, 916-19; Kelly 2 Tr 1052-58, 1130-32, 1142, 1151-53 (recommending the Commission approve the Company's proposal); Coppola 2 Tr 1935-48; Fitzhenry 6 Tr 3734-35; Schiller 6 Tr 4295; Durfee 6 Tr 4417-19 (recommending certain cost recovery disallowances).~~

Tr 4295; Durfee 6 Tr 4417-19 (recommending certain cost recovery disallowances).

The Company proposed significant capital expenditures for the HVD system in its filing, specifically $542,846,000 for the bridge period and $417,546,000 for the test year. (See Hayward 3 Tr 718-79.) As the Company did not demonstrate these costs or projects are necessary, reasonable, or prudent the Commission should reject the Company's proposal.

The Company's proposal should be considered in the context of the Audit, which did not find a substantial need or benefit to increased investment in HVD lines or substations given that most SAIDI minutes, and most projected SAIDI improvements, are related to the LVD system. (Kelly 2 Tr 945.) This is confirmed by the Company's recent outage data, which shows that none of the outages reported in Table CTF-2 above occurred at a fault location with a voltage level exceeding 24.9 kV.[8] (Fitzhenry 6 Tr 3733-35.) Furthermore, Transmission/Generation outages accounted for only 0.4% of the total CMI, meaning almost the entirety of outages over the last three years (2022-2024) were the result of a fault that occurred in the LVD System. (*Id*.) Recent outage data therefore does not suggest there is a need to make investments to improve the reliability of the HVD system, particularly on the scale proposed by the Company.

As such, the Commission should only approve capital expenditures equivalent to the 2024 levels for the HVD reliability programs; i.e., $32,263,573 for the HVD Lines Reliability program and $5,715,476 for the HVD Substations Reliability program. Implementing this recommendation

[8] The Company claimed that "Figures 42, 43, and 45 in Company witness Michael P. Kelly's direct testimony clearly show that outages on HVD lines and on substations are causing SAIDI over the last three years, so it is not accurate to claim that all outages are LVD-related." (Hayward 2 Tr 917-18.) These figures demonstrate that HVD lines and substations made up a sliver of SAIDI and represented outage minutes of approximately only up to 6 and 3 minutes, respectively. (Kelly 2 Tr 112-14.) This hardly justifies the tens of millions of dollars (or "huge amounts of capital investment," as characterized by Consumers) sought by the Company. (Hayward 2 Tr 917-18.)

would reduce capital expenditures by the following amounts compared with the Company's proposal:

- HVD Lines Reliability program:
    - Bridge period reduction of $90,648,903.
    - Test year reduction of $75,403,427.
- HVD Substations Reliability program:
    - Bridge period reduction of $39,711,365.
    - Test year reduction of $33,964,524.

b. HVD lines reliability (ROW acquisition).[9]

References in the Record: Hayward 2 Tr 756, 916 (arguing the Commission should approve the Company's proposal); Coppola 2 Tr 1410-12; York 6 Tr 3702-03; Boutet 6 Tr 4377-79 (recommending cost recovery disallowance).

The Company requested cost recovery of $12.667 million in the Bridge Period and $11 million in the Test Year for ROW Acquisition. (Hayward 2 Tr 756.) As the Company did not adequately support the reasonableness of these projects or the prudency of cost recovery the Commission should disallow the same.

The Company asserted that it *may* need to acquire new rights of way or expand existing ones during these periods. (*Id.*) As such, these costs are speculative. Furthermore, while Consumers' investment estimate is based on the most recent actual ROW costs for an executed project, it did not provide actual historical data for ROW Acquisitions or details associated with the "most recent actual ROW costs for an executed project." (*Id.*) As such, despite its claims

[9] ~~This issue is addressed at Hayward 2 Tr 756, 916 (arguing the Commission should approve the Company's proposal); Coppola 2 Tr 1410-12; York 6 Tr 3702-03; Boutet 6 Tr 4377-79 (recommending cost recovery disallowance).~~

regarding ROW costs in historical years and certain projects for which ROW procurement is needed, its cost projections are inadequately supported. (Hayward 2 Tr 916.)

The Company therefore failed to satisfy its burden to demonstrate its cost projections are reasonable or that cost recovery would be prudent here. As such, the Commission should disallow cost recovery for these capital expenditures at this time. (York 6 Tr 3702-03.)

c. HVD strategic customers new business – 138 kV dedicated customer substation.[10]

References in the Record: Hayward 2 Tr 848, 853-54, 915-919 (recommending the Company's proposal); Fitzhenry 6 Tr 3735-37; York 6 Tr 3702 (recommending cost recovery disallowance).

The Company requested cost recovery of $4.340 million in the Bridge Period and included $20.619 million in the test year for a new substation for a single dedicated customer in west Michigan, although the project was canceled as of July 2025 and the Company is in the process of cancelling the work orders. (Hayward 2 Tr 848, 915-19; Fitzhenry 6 Tr 3735-37.) This project was therefore never completed and, since it was designed for a single dedicated customer, was never considered used and useful. It would therefore be neither reasonable nor prudent to include this expenditure in the test year. (*Id.*)

The Company stated that if and when the Company recovers these costs from the customer, that money will be credited to this subprogram and netted back out of rate base. (*Id.*) This is not a reasonable or prudent approach to cost recovery and shifts the risk associated with the Company's direct dealings with specific customers onto its general ratepayers who were not involved in the subject contract negotiation or relationship. The Company was in the position to secure its expenditures, not customers, and ratepayers should not backstop the Company's potential loss here

[10] ~~This issue is addressed at Hayward 2 Tr 848, 853-54, 915-919 (recommending the Company's proposal); Fitzhenry 6 Tr 3735-37; York 6 Tr 3702 (recommending cost recovery disallowance).~~

with nothing but the prospective of recovery, a process in which, again, customers will play no part. The Company's claim that disallowing this amount "would create a disincentive for the Company to make needed investment to accommodate new large customers, since there would be an implied risk that the customer could cancel the deal and leave the Company suddenly facing reasonable and prudent investments that it could not recover on," is a backward view of the appropriate balance of risk here. (Hayward 2 Tr 915-16.) Instead, this approach *incentivizes* the Company to ensure its contracts with these customers are secure and protective and will not leave ratepayers holding the bag, subject to potential recoupment.

The Company contracted with this customer and bears the risk of collecting its costs, not ratepayers. As such the Company should not be permitted to recover these costs from ratepayers and should instead pursue any requested cost recovery directly from the customer at issue. (York 6 Tr 3702.)

d. LVD asset relocations.[11]

References in the Record: Partlan 2 Tr 1414, 1435-45 (recommending the Commission approve the Company's proposal; Coppola 2 Tr 1901-05; York 6 Tr 3701 (recommending cost recovery disallowances).

The Company projected $97.911 million of investment in the Bridge Period and $79.090 million in the Test Year for this program. (Partlan 2 Tr 1414, 1435-45.) Because these projected costs represent a dramatic increase from historic actual costs and were inadequately supported the Commission should disallow cost recovery for the same.

The Company's five-year average annual historical spend for this expenditure category was $44.604 million, and its 2024 actual spend was only $51.502 million. (Exhibit A-113.) In

[11] ~~This issue is addressed at Partlan 2 Tr 1414, 1435-45 (recommending the Commission approve the Company's proposal; Coppola 2 Tr 1901-05; York 6 Tr 3701 (recommending cost recovery disallowances).~~

addition to the significant divergence between historic and projected costs, Consumers only identified specific projects amounting to roughly $7 million of the projected spend in the Bridge Period and in the Test Year. (Partlan 2 Tr 1440-45.) The vast majority and remainder of the projected costs are highly uncertain, as they are entirely driven by requests from external stakeholders. (*Id*.) The Company provided no indication that such requests will dramatically increase to account for the large increase in projected costs. Instead, the Company explained that customer requested relocations are commonly associated with home remodeling work, which slowed as interest rates rose at the end of 2023. (*Id*.)

Consumers' identification of only a small portion of specific bridge period and test year projects demonstrates that a large share of projected spending is speculative. (Partlan 3 Tr 2064.) This is particularly critical for externally-driven categories of spending that are sensitive to broader market factors. Again, prudent ratemaking and the Company's burden as described by the Commission requires capital recovery to be justified through well-documented, identified projects or reliable, transparent methods. The Company should provide transparent, project-level evidence, especially since LVD Asset Relocations has considerable cost variability. Aggregate historical growth rates and summaries are not a sufficient standalone basis for approving capital increases without clarity on drivers, segments and timing, and broad growth projections which are inherently questionable without adequate supporting evidence. It is not reasonable (nor does it satisfy the Company's burden) to simply assume continued robust growth in Make-Ready and Customer-Requested work when some recent peaks appear driven by non-recurring events (e.g. federal broadband stimulus) rather than ongoing long-term trends. Stated differently, ratepayers should be subject to over-collection on the basis of broad, uncertain projections.

The Company's cost projections are significantly above its actual historic costs and based on unknown external stakeholder requests. As such the Commission should not approve projected capital expenditures for this program in each of these periods above the actual level experienced in 2024, and should instead reinforce the expectation for greater transparency and specificity in future capital requests for asset relocations. This approach would reduce the Company's projected capital expenditures by $46.409 million and $27.587 million in the Bridge Period and Test Year, respectively. (York 6 Tr 3701.)

e. LVD lines reliability.[12]

References in the Record: Kelly 2 Tr 1023-24, 1047-52, 1129-31, 1141-42; Partlan 2 Tr 1149-81 (recommending the Commission approve the Company's proposal); Coppola 2 Tr 1905-12, 2053-56, Dauphinais 6 Tr 3650; York 6 Tr 3678-81; Fitzhenry 6 Tr 3719-21 (recommending disallowances and adjustments to the Company's request); Bunch 6 Tr 4072 (recommending recovery of $127.5 million of capital expenditures related to the LVD Lines Reliability-pole replacement program); Schiller 6 Tr 4294-97; Boutet 6 Tr 4363-67; Durfee 6 Tr 4426-31; Evans 6 Tr 4457 (recommending certain cost recovery disallowances).

The Company requested cost recovery for the LVD Lines Reliability Subprogram of $180,763,000 for the 16-month bridge period ending April 30, 2026 and $312,886,000 for the 12-month test year ending April 30, 2027, although the majority of the LVD Lines Reliability Subprogram capital expenditures ($276,191,000 in the test year) are being proposed for recovery through the IRM surcharge. (See Exhibit A-166 at 14, Exhibit A-167 at 10, Kelly 2 Tr 1023.) The

[12] This issue is addressed at Kelly 2 Tr 1023-24, 1047-52, 1129-31, 1141-42; Partlan 2 Tr 1149-81 (recommending the Commission approve the Company's proposal); Coppola 2 Tr 1905-12, 2053-56, Dauphinais 6 Tr 3650; York 6 Tr 3678-81; Fitzhenry 6 Tr 3719-21 (recommending disallowances and adjustments to the Company's request); Bunch 6 Tr 4072 (recommending recovery of $127.5 million of capital expenditures related to the LVD Lines Reliability-pole replacement program); Schiller 6 Tr 4294-97; Boutet 6 Tr 4363-67; Durfee 6 Tr 4426-31; Evans 6 Tr 4457 (recommending certain cost recovery disallowances).

Company has not met its burden to demonstrate cost recovery for these projected expenditures is reasonable or prudent and the Commission should disallow the same here.

While the Commission approved some of the Company's proposed expenditures for this program in Case No. U-21585, it rejected cost recovery for others. *In the Matter of the Application of Consumers Energy Co*, order of the Public Service Commission, entered March 21, 2025 (Case No. U-21585), pp 54-64. For instance, for Zonal Health Improvements and Right-of-Way ("ROW") acquisitions, the Commission agreed with the ALJ that the Company's evidence was insufficient. *Id*. Specifically, the Commission found that Consumers failed to provide historical cost data for the relabeled "Zonal Health" program and did not adequately justify the significant spending increase, and that for ROW acquisitions Consumers failed to provide necessary detail linking projected costs to specific projects. *Id*. Specifically, the Commission stated that "[s]hould the company seek recovery in a future electric rate case, it is incumbent upon the utility to produce more complete cost information, including historical costs, from which the parties and the Commission can evaluate the reasonableness of future projections." *Id*. Further, the Commission asserted its expectation that Consumers would provide "additional detail in future electric rate cases regarding line items that have been recategorized, the past spending levels for those line items, how historical spending for any relabeled line items compares to proposed expenditures, and clarity on how these investments deliver value for the company's customers." *Id*. More generally, the Commission stated that "it remains unclear whether the proposed levels of capital investment represent an optimized approach for maximizing customer benefit, including a reduction in SAIDI, particularly given the relatively flat level of expenditures focused on tree trimming," and "[p]rior to approving a 500% increase in capital spending for zonal health between the bridge period and test year, the Commission will want to see more analysis of the most cost-

effective opportunities to drive improvement in reliability performance, using the results of the recent third-party audit in Case No. U-21305 as a starting point." *Id*. The Commission also noted "concerns about the level of workforce in place to warrant the company's ambitious expenditures." *Id*. The Commission also disallowed cost recovery for secondary conversions, finding that the significant ramp-up in spending was not sufficiently supported with details on the benefits to a relatively small number of customers. *Id*. Specifically, the Commission stated that Consumers' "planned investments target a relatively few number of customers and involves a significant ramp up in spending, from $1.0 million in the bridge period to over $28 million in the test year" without necessary "additional details supporting the benefits of these conversions are necessary prior to approval for inclusion in rate base of such a significant increase in expenditures." *Id*.

The Commission therefore explicitly stated that Consumers must support its cost recovery requests for this category with more complete historical data and a clear justification and explanation of how the investments improve service reliability and deliver value to customers. As set out below, numerous cost recovery requests in this proceeding do not satisfy this request or meet the Company's burden to demonstrate recovery is reasonable or prudent.

i. LVD pole replacement.~~[13]~~

References in the Record: Daly 2 Tr 635 (responding to MNSC pole replacement investment recommendations); Kelly 2 Tr 943, 1162-63; Partlan 2 Tr 1468-72, 1480-81 (recommending the Commission approve the Company's proposal); Coppola 2 Tr 1911; Fitzhenry 6 Tr 3721-23 (recommending cost recovery disallowances); Jester 6 Tr 3996-97; Bunch 6 Tr 4054-55, 4060 (addressing the Company's proposal).

~~[13] This issue is addressed at Daly 2 Tr 635 (responding to MNSC pole replacement investment recommendations); Kelly 2 Tr 943, 1162-63; Partlan 2 Tr 1468-72, 1480-81 (recommending the Commission approve the Company's proposal); Coppola 2 Tr 1911; Fitzhenry 6 Tr 3721-23 (recommending cost recovery disallowances); Jester 6 Tr 3996-97; Bunch 6 Tr 4054-55, 4060 (addressing the Company's proposal).~~

For instance, the Company proposed to increase pole replacements from 2,300 in 2025 to 12,500 in 2027, which will cost $127,500,000 in the test year period. (See Exhibit A-167 at 6; Partlan 2 Tr 1468-71; Kelly 2 Tr 943; Exhibit A-129 at 69.) As the Company's methodology underlying its approach is flawed the Commission should reject this proposal.

The Audit found that Consumers' LVD poles ages are consistent with those of other large electric utilities, that the observed rate of poor pole conditions requiring management attention was low, did not find what it would consider high numbers of poles with material condition issues, and did not observe significant numbers of safety issues involving poles. (Audit Part I at 18, 39.) Furthermore, Consumers recognized that the Audit "recommended the Company place less emphasis on asset age when deciding whether to replace assets," which the Company "generally agrees with." (Kelly 2 Tr 943.) Despite this generally agreement, however, when determining the forecasted rejection rate for pole replacements the Company solely relied on asset age. (See Fitzhenry 6 Tr 3721-23.) Specifically, the Company assumed the following: (i) all poles with a vintage between 1937-1960 are considered high risk and will have a greater than 15% rejection rate; (ii) poles with a vintage between 1961-1980 are considered moderate risk poles and have a 10%-15% rejection rate; and (iii) poles with a vintage between 1981-2025 are considered minor risk and have less than a 10% rejection rate. (Exhibit A-129 at 69.) The Company used these assumed rejection rates by age and weighted those values based on the average age of the population of distribution poles, which provided its estimated 10% rejection rate for all poles.[14]

[14] While the Company claimed it "is not proposing to use age as the deciding factor in replacing LVD pole," it also asserted that it "needed to create a reasonable estimate of how many rejected poles were likely on the system" and "[a]ge is a reasonable proxy in developing this kind of analysis, since age is correlated with deterioration of the wood." (Partlan 3 Tr 2065-66.) In other words, the Company's projected costs are based on estimates derived from age, which is not reasonable and should not be used as a basis for establishing cost recovery.

This approach directly contravenes the Audit's findings and recommendations. Rather than using an estimate based on assumptions Consumers should utilize a sample of pole inspections to make a more accurate determination of an appropriate rejection rate. (Fitzhenry 6 Tr 3721-23.) A properly selected sample allows for a reliable assessment of the entire population and provides the most practical way to estimate the overall rejection rate of a much larger population of poles, particularly given the significant discrepancy between historic and projected test year costs here.

The Company's alternative is unreasonable and should be rejected. A more appropriate rejection rate estimating the number of pole replacements during groundline inspections is 5%, as it is at the higher end of rejection rates when comparing the actual rejection rates of utilities who have utilized groundline inspections for pole replacement. (*Id.*) Reducing the rejection rate to 5% reduces the Company's proposed capital expense for pole replacement by 50%, which adjustment reduces the Company's proposed authorized IRM capital expenditures by $63,750,000 in both the test year period and the year after.

ii. LVD targeted circuit improvement – rejuvenating vintage underground cable.[15]

References in the Record: Kelly 2 Tr 1023-26; Partlan 2 Tr 1452-53, 1459, 1477, 1480, 2066-67; Partlan 3 Tr 2043-44 (recommending the Commission approve the Company's proposal); Fitzhenry 6 Tr 3723-25; Boutet 6 Tr 4377-79 (recommending certain cost recovery disallowances).

The Company's LVD targeted circuit improvement plan includes projected costs for four distinct project categories, including rejuvenating vintage underground cable ($65,989,000). (See Exhibit A-167.) As the Company has not demonstrated the projected costs for rejuvenating vintage

[15] ~~This issue is addressed at Kelly 2 Tr 1023-26; Partlan 2 Tr 1452-53, 1459, 1477, 1480, 2066-67; Partlan 3 Tr 2043-44 (recommending the Commission approve the Company's proposal); Fitzhenry 6 Tr 3723-25; Boutet 6 Tr 4377-79 (recommending certain cost recovery disallowances).~~

underground cable will produce adequate customer benefits the Commission should reject cost recovery.

The Commission has stated that the purpose of the Company's IRM is to address "safety and reliability." *In the Matter of the Application of Consumers Energy Co*, order of the Public Service Commission, entered March 1, 2024 (Case No. U-21389), p 273. The vintage underground cable rejuvenation project involves the replacement of cable that is already located underground, meaning any associated safety and reliability benefits of undergrounding have already been realized by the Company. (Fitzhenry 6 Tr 3722-25.) This project is therefore more accurately characterized as preventative maintenance, which would only provide future benefits in the event that an existing underground cable fails. Indeed, the Company acknowledged that "investment in the Reliability program is, to some extent or another, proactive; the Company is making an investment today in order to prevent an outage in the future." (Partlan 3 Tr 2067.) This type of project therefore falls outside of the intended scope of the IRM, meaning the Company is proposing to utilize its IRM for cost recovery beyond the intended purpose of the IRM.

Furthermore, the Company failed to quantify the benefits of rejuvenating vintage underground cable, despite requesting an additional $38,080,000 in capital expenditures in the test year above amounts included in the bridge period. As set out above, the Company has the burden to demonstrate the reasonableness of its projections, particularly when they deviate from historic costs. The Commission should therefore reject the Company's request for additional capital expense for vintage underground cable rejuvenation in the test year period. Since the bridge period is 16 months, the average monthly capital expenditures would be $1,744,312. Applying the monthly capital expenditures to the 12-month test year period would result in an annual expense

of $20,931,750. This adjustment reduces the Company's proposed authorized IRM capital expenditures by $45,057,250 in both the test year period and the year after.

f. LVD lines rehabilitation.[16]

References in the Record: Partlan 2 Tr 1489-99 (recommending the Commission approve the Company's proposal); York 6 Tr 3697-98 (recommending cost recovery disallowances).

This category of expenditures includes two subprograms for which specific projects cannot be identified, namely the Modem Replacement Program and Meter Voltage Anomalies. (Partlan 2 Tr 1495-96.) Because the Company did not support the majority of its projected spending for these subprograms the Commission should disallow cost recovery for the same.

For the Modem Replacement Program, the Company claimed that because it only creates orders for specific modems close to the time that they are replaced, there are no specific projects listed for this investment category and projected spending is based on an assumption of the same volume of work going forward. (*Id.*) Similarly, the Company stated that it does not have specific projects identified for the Meter Voltage Anomalies subprogram and does not identify such projects until closer to the time of project execution. (*Id.*) These subprograms account for approximately 37% and 54% of the projected Bridge Period and Test Year LVD Lines Rehabilitation spending, respectively. (York 6 Tr 3698.) In other words, the Company does not have specific projects identified for the majority of its projected LVD Lines Rehabilitation costs.

The Company claimed that these activities involve numerous small individual jobs each year, such as 800 modem replacements, and asserted that full lists are not practical or historically required. (Partlan 3 Tr 2059-60.) This misstates the Company's burden. The issue here is not the

[16] ~~This issue is addressed at Partlan 2 Tr 1489-99 (recommending the Commission approve the Company's proposal); York 6 Tr 3697-98 (recommending cost recovery disallowances).~~

lack of a list for every single location, but rather the fact that substantiating projected spending increases requires transparent, granular evidence linking forecasts to documented need, historical trends, and rate case prudency standards. As the Commission has stated, its "expectation is that the parties will fully document the basis for their test year projections by offering into evidence detailed supporting explanations and underlying assumptions rooted in expected business, financial, and economic circumstances," and "[r]ate applications may not rely on undocumented estimates of future ratemaking expenses and revenue criteria." *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered May 8, 2020 (Case No. U-20561), p 13. Bulk programs can and should be supported by clear metrics, program scopes, failure rates, historical volumes, average unit costs, and technical justification for continued or expanded levels of investment. The absence of project lists does not alleviate the need for a robust justification and review for all investment categories, including new ones like meter voltage anomalies. For any new investment category seeking significant funding, a sound basis must be provided, such as detailed unit pricing, quantification of expected reliability benefits, and alignment with industry benchmarks.

If the Company cannot provide this level of support, it is necessary and consistent with regulatory precedent to limit funding to historical averages, particularly when ratepayers are being asked to fund expansion of undefined or poorly supported initiatives. This approach protects ratepayers while incentivizing the Company to advance data-driven planning and transparent project justification. Should further detail and evidence become available in future cases, increased funding could then be justified and prudently approved. In other words, prudent regulation requires substantiated requests, transparency, and protection of ratepayers. Approving funding for unspecified future projects, particularly in the test year, exposes ratepayers to unnecessary risk and

does not align with best practices for prudent capital recovery, nor is it consistent with the Commission's obligation to ensure the Company meets its burden to demonstrate cost recovery is reasonable and prudent. Where project-level or programmatic detail is lacking, the Commission should approve funding based on historic averages, not on unsupported expansions.

The Company has failed to meet its burden to demonstrate cost recovery for these subprograms is reasonable or prudent. As such the Commission should only approve projected Bridge Period and Test Year capital expenditures for the entire LVD Lines Rehabilitation category at the five-year average level shown on Exhibit A-113 (MPK-3), line 17. This adjustment removes $2.975 million from the Bridge Period and $5.078 million from the Test Year.

g. LVD resiliency – overhead to underground conversions.[17]

References in the Record: Kelly 2 Tr 943, 983, 987-88, 1135-38, 1143-50, 1164-65; Partlan 2 Tr 1506-08, 1511, 1513 (recommending the Commission adopt the Company's proposal); Coppola 2 Tr 1912-17; Fitzhenry 6 Tr 3725-29; Bunch 6 Tr 4060-65 (recommending certain cost recovery disallowances).

The Company proposed $1.25 million in bridge period capital expenses for Overhead to Underground Conversions and $20 million in the test year. (Exhibit A-132 at 27; Kelly 2 Tr 943, 983, 988; Partlan 2 Tr 1513.) As this project requires further analysis the Commission should reject the Company's proposal.

The Audit recommended the Company delay expanding this program beyond the initial pilot phase because, at the time of the audit, there were not grounds to support a full-scale expansion. (Audit Part II at 70-71.) The Audit cited significant uncertainties regarding the actual costs and reliability benefits and suggested that a major expansion in annual expenditures should

[17] ~~This issue is addressed at Kelly 2 Tr 943, 983, 987-88, 1135-38, 1143-50, 1164-65; Partlan 2 Tr 1506-08, 1511, 1513 (recommending the Commission adopt the Company's proposal); Coppola 2 Tr 1912-17; Fitzhenry 6 Tr 3725-29; Bunch 6 Tr 4060-65 (recommending certain cost recovery disallowances).~~

be delayed by at least a year or more, and potentially reduced, based on the lessons learned from the pilot projects. (*Id*.) Further, the Audit noted that historically undergrounding has been much more expensive than overhead construction, and while it can be a good resiliency measure in specific areas, like those with high tropical storm or wildfire exposure, its benefit at the levels identified in the Electric Distribution Infrastructure Investment Plan were not clear. *Id*. The Audit also questioned whether the reliability improvements from undergrounding are significantly better than those from less costly alternatives, such as accelerated tree trimming. *Id*.

Indeed, the Present Value of the Revenue Requirement ("PVRR") for the undergrounding pilot projects as presented by the Company demonstrated that according to the Company's own data and using the Utility Cost Test ("UCT"), undergrounding is the most expensive option when compared to Aerial Spacer Cable including Forestry, Tree Wire Including Forestry, and Existing Overhead Including Forestry using the utility cost test ("UCT"). (Kelly 2 Tr 983, 1149 ("Figure 26 in my direct testimony does show that OHUG is more expensive than alternatives at scale").) While the results of a Societal Cost Test ("SCT") demonstrated that Undergrounding is the least cost option, the SCT uses a lower discount rate than the UCT, which assigns more value to benefits further out in the investment lifecycle when the benefits are more speculative.[18] (*Id*.; Fitzhenry 6 Tr 3726-30.) The further out in time one makes assumptions regarding potential costs and benefits, the less certain or reasonable they are. As such this approach does not provide an appropriate basis for approving millions of dollars in cost recovery. Thus, even considering the SCT (which the Commission should not considering the speculative nature of the benefits included therein), the

[18] The Company's claim that ABATE "never clearly states" its concerns regarding the SCT and "does not provide any support for why the SCT is inappropriate to use" indicates a demonstrated lack of engagement with ABATE's testimony on this point. (Kelly 2 Tr 1149.)

Company has not demonstrated that Undergrounding is consistently the preferred solution considering both cost tests.

Furthermore, the Company acknowledged that the Undergrounding Pilot was not completed as planned due to challenges with securing easements on four of the undergrounding projects that were originally approved in Case No. U-21389. (Fitzhenry 6 Tr 3726-30.) These four projects and the reasons for the delays are as follows:

- Blue Star-Pier Cove LCP 622: A group of landowners in this area opposed the project as designed, requiring significant design changes and leading the Company to defer the project beyond the period covered by Case No. U-21389. All easements have since been acquired for this project to move forward.

- Dean Road-Hogan LCP 951: Multiple landowners had concerns with the initially proposed alignment for this project, but the Company has redesigned the project to use the road right of way instead. All easements have since been acquired for this project to move forward.

- Peck Road/M-91 LCP 473: This is an unusually complex project in terms of the number of easements required, and the Company's easement acquisition process has taken longer than expected. The design for this project took longer than expected, which delayed starting easement acquisition.

- Merson-Merson LCP 412: This project involved landowners requesting a number of changes, such as working around septic systems and drain fields. The Company anticipates acquiring these remaining easements in September 2025. (*Id*.)

The Company's proclamations that "[a]ny plan may require changes when it faces the reality of execution" and a "hallmark of a successful organization is that it can make adjustments and adapt as challenges arise," while perhaps motivational, do not support approving cost recovery for an extraordinary increase in this program's scope considering these obstructions. (Kelly 2 Tr 1150.) Instead, considering these obstacles, the scope of the Company's proposal is alarming. Specifically, the Company is proposing to scale the size of the undergrounding program from 8.8 miles completed in the Pilot to 400 miles. (*Id*.) Considering the issues the Company already experienced with less than 9 miles of this effort, the potential for those issues to proliferate and

compound over an additional 390 miles is concerning and counsels caution. Furthermore, if the Company changes its proposed projects from one circuit to another due to issues with landowners, such as those it has already encountered, the benefits of undergrounding in the alternate circuit may not be as great as the benefits in the originally identified circuit. (*Id*.) This would further reduce the cost-effectiveness of the program.

The Commission should therefore reject the Company's proposal to greatly expand this program. While undergrounding may have conceptual appeal, the Company has not provided sufficient justification to move forward with a full-scale expansion at this time. Instead, Consumers' own data demonstrates that undergrounding is the most expensive option under the UCT, while the reliance on the SCT to justify the program places a high value on long-term, uncertain benefits, and is therefore speculative. Further, the Company's experiences with this program to date demonstrate significant real-world challenges and impediments. The issues encountered in securing easements, which led to project delays and redesigns, highlight a major logistical hurdle. (*Id*.) This lack of demonstrated ability to efficiently execute the program, coupled with the uncertainty of cost and benefits, makes the current proposal imprudent.

The Audit's recommendation to take a more measured approach is instead a more reasonable step at this time. The Commission should therefore require the Company to complete and thoroughly analyze the initial pilot projects before committing to such a massive capital expenditure expansion. This will allow for a more accurate assessment of actual costs and benefits and will ensure that any future expansion is based on sound data and a proven ability to execute, rather than on unsubstantiated and speculative projections. Again, the Company has the burden to demonstrate its investments will produce tangible improvements for customers before dramatically

increasing program expenditures. Maintaining the current scope of this program would reduce the Company's test year capital expenditures by $20 million.

h. LVD new business capacity.[19]

References in the Record: Kelly 2 Tr 1019-21; Partlan 2 Tr 1414-23, 1525-30 (recommending the Commission approve the Company's proposal); Coppola 2 Tr 1898-1901, 1944; York 6 Tr 3702 (recommending cost recovery disallowances); Evans 6 Tr 4447, 4445 (making recommendations regarding this issue).

The Company projected $38.180 million of investment in the Bridge Period and $30.130 million in the Test Year for this program. (Partlan 2 Tr 1526-28.) As this projection was not adequately supported and is highly speculative the Commission should disallow cost recovery for the same.

Spending in these categories is customer-driven and therefore largely uncertain. (*Id.*; York 6 Tr 3699.) Indeed, the Company identified only $8.463 million of costs is projects will occur in the Bridge Period, noted that additional work will be required, and acknowledged that it has not identified any specific projects for the Test Year. (*Id.*; Exhibit A-166.) The Company's cost projection is therefore inadequately supported and cannot be considered reasonable or prudent.

Historic spending must also be considered in context. The Company's assertions here regarding recent historic spending do not support its request or demonstrate it is reasonable. (Partlan 3 Tr 2060-61.) Recent growth spikes do not necessarily justify continued increases without clear evidence of sustained, quantifiable future demand. Thus, relying solely on one or two years of above-average actuals can be misleading, especially in programs where annual variability is high due to external factors (e.g., customer requests, economic cycles). Furthermore,

[19] ~~This issue is addressed at Kelly 2 Tr 1019-21; Partlan 2 Tr 1414-23, 1525-30 (recommending the Commission approve the Company's proposal); Coppola 2 Tr 1898-1901, 1944; York 6 Tr 3702 (recommending cost recovery disallowances); Evans 6 Tr 4447, 4445 (making recommendations regarding this issue).~~

new business demand is sensitive to interest rates, broader economic conditions, and policy changes, all of which inject high uncertainty into forward-looking projections. Spending for this program should therefore be set to the five-year average (or a slightly escalated version) unless Consumers provides compelling documentary support for its asserted future growth.

Because actual spending in these categories will be driven by customer requests, which are unknown at this time, it would be more reasonable and prudent to limit the projected investment in this category to the five-year average actual spend shown on Exhibit A-113 (MPK-3), line 25 for both the Bridge Period and Test Year. Any additional amount would be speculative and baseless. This adjustment would remove $11.958 million from the Bridge Period and $3.907 million from the Test Year.

i. LVD transformers.[20]

References in the Record: Partlan 2 Tr 1543-48 (recommending the Commission approve the Company's proposal); Coppola 2 Tr 1921-25; York 6 Tr 3699-700 (recommending cost recovery disallowances).

The Company projected $227.963 million of investment in the Bridge Period and $207.782 million in the Test Year for this program. (Partlan 2 Tr 1545-46.) Because these projections represent significant increases from actual historic spend and are inadequately supported the Commission should reject the Company's proposal.

These projections must be considered in the context of the Company's historic costs for the program category. Specifically, the Company's five-year average annual historical spend is only $60.603 million while the 2024 actual spend was $122.886 million. (*Id.*) In addition to the fact that the Company's projections dramatically exceed actual historic costs, they are based on an

[20] This issue is addressed at Partlan 2 Tr 1543-48 (recommending the Commission approve the Company's proposal); Coppola 2 Tr 1921-25; York 6 Tr 3699-700 (recommending cost recovery disallowances).

estimated number of transformers needed and assumptions regarding the future. (*Id*.; York 6 Tr 3700.) Specifically, the Company asserted that it is planning for continued significant increases in purchases of padmount transformers tied to increased ungrounding work for both new service connections, general new business work, the need to support customers adopting electric vehicles, and ensuring it has restocked its inventory. (*Id*.) These planned expenses are highly inexact and cannot serve as a basis for determining these cost projections or cost recovery related thereto is reasonable or prudent. Investments in new business and support for electric vehicle adoption are highly uncertain. (Partlan 3 Tr 2062; York 6 Tr 3700.) Furthermore, the Company's plan to increase padmount transformer purchases does not correlate with customer benefits or their actual use in providing service, particularly in the bridge period or test year. (*Id*.) The Company's hedging strategy should not receive blanket ratepayer funding, particularly without substantiated procurement or deployment plans. The Company should also provide clearer documentation differentiating between purchases required for operational need and those intended as inventory hedging before cost recovery can be considered reasonable or prudent.

Generally, therefore, conservative budgeting should apply when forecasting is speculative, as in the case of electric vehicle adoption. Furthermore, large year-over-year capital increases should be supported by a clear pipeline of identified projects, purchase orders, and demonstrable need, consistent with the Company's burden as described by the Commission. Test year and bridge year projections should be tied to detailed supporting evidence such as upcoming undergrounding locations and schedules, anticipated new business loads, and market research or applications for infrastructure expansion. Without adequate support for its projections, maintaining revenue at 2024 actuals captures recent real growth in demand while moderating risk from overly optimistic

projections. This approach protects ratepayers during a period of economic uncertainty and prevents over-collection for inventory that might not be ultimately needed.

A more reasonable and prudent approach to projecting capital expenditures for LVD Transformers would thus be to use 2024 actual capital expenditure amounts for both the Bridge Period and Test Year. (*Id*.) This captures the significant increase in spend that occurred in 2024 relative to prior years while also recognizing the speculative nature and uncertainty of the actual expenditures for this cost category going forward. As such, until Consumers provides a more granular justification for accelerated capital growth, this balances reliability with fiscal responsibility. This recommendation would reduce the Company's projected capital expenditures by $105.077 million and $24.292 million for the Bridge Period and Test Year, respectively.

j. Line regulator controller project.[21]

References in the Record: McPhail 2 Tr 1223-30, 1286-90 (recommending the Commission approve the Company's proposal); Coppola 2 Tr 1949-50; Fitzhenry 6 Tr 3730-33 (recommending the Commission reject the Company's proposal).

The Company projected $10,526,000 for the bridge period and $5,120,000 for the test year to upgrade 220 regulator locations in 2025 and 217 locations in 2026, which is projected to be the final year of the mass deployment. (See Exhibit A-146.) The projected capital expenditures for this project are $10,526,000 for the bridge period and $5,120,000 for the test year. (*Id*.) As the Company's BCA for this program is flawed the Commission should reject this proposal.

The Company's BCA included a discount cash flow ("DCF") model which treated the initial investment as a negative cash flow and future benefits as positive cash flows, which were then discounted to their Net Present Value ("NPV"). (Fitzhenry 6 Tr 3730-33.) This approach

[21] This issue is addressed at McPhail 2 Tr 1223-30, 1286-90 (recommending the Commission approve the Company's proposal); Coppola 2 Tr 1949-50; Fitzhenry 6 Tr 3730-33 (recommending the Commission reject the Company's proposal).

excluded and did not consider several key costs, such as taxes, Return on Equity ("ROE"), interest, and stranded costs.[22] (*Id*.) As part of their rates Consumers' customers pay these costs through the Company's revenue requirements after an investment is put into service. Not accounting for them in the BCA therefore underestimates the true financial burden on customers. Similarly, if an asset is replaced before the end of its depreciable life, customers are forced to pay for both the original, now-retired asset and its replacement (i.e., stranded costs). This double payment represents a significant financial risk to ratepayers that the BCA ignores. In addition, the model also fails to reflect the interest paid on debt used to finance the project. This is another cost ultimately borne by ratepayers that is not reflected in the analysis.

Excluding these costs produced a flawed BCA and a misleading picture of the project's cost-effectiveness. (Fitzhenry 6 Tr 3730-33.) Without factoring in these significant real costs to customers the potential net benefits are artificially inflated because they are not offset by the full spectrum of costs customers will ultimately pay. Properly including taxes, ROE, interest expense, and potential stranded costs would demonstrate the project's true costs are significantly higher than those claimed in the Company's BCA and that the project is less cost-effective than the Company claimed. Ultimately, therefore, the Company's BCA modeling approach is inappropriate for making investment decisions that will impact customer rates.

In addition to excluding necessary costs, the Company's input assumptions are also unreasonable. While a majority of the monetized benefits ($12,880,000) were calculated based on the assumption that current line regulators installed prior to 2000 will *all fail* over the next ten years, the Company provided no analysis to support this drastic assumption. (*Id*.) Excluding the

[22] The Company explicitly agreed that "a utility has other costs beyond the initial purchase and installation price such as taxes, ROE" which are not included in the Company's BCA. (McPhail 2 Tr 1288-90.)

forecasted benefit of future line regulator failures would reduce the NPV of benefits to $10,726,493, which is $4,402,645 less than the cash value of the project. Alternatively, even if only 273 of the line regulators installed prior to 2000 fail, then the project's net benefits would be negative, and the project would no longer be forecasted to be cost-effective. (*Id.*)

Given these flaws the Commission should reduce the Company's proposed pace for the line regulator controller project to 25% of the proposed installation rate. This would reduce the Company's plans to upgrade 220 regulator locations in 2025 and 217 locations in 2026 to 55 regulator location in 2025 and 54 locations in 2026. Such an approach would allow the Company to utilize actual historical data to validate and improve the input assumptions used in the line regulator controller BCA model.[23] Along with this reduced pace, the requested capital expense should also be reduced by a corresponding 25%. This would reduce the Company's projected capital expenditures for this project by $7,894,500 for the bridge period and $3,840,000 for the test year. (*Id.*)

2. Generation capital expenditures.

The Company proposed generation capital expenditures amounts of $275.408 million during the Bridge Period and $188.638 million in the projected test year. (Exhibit A-12 Schedule B-5.) This is an increase in capital expenditures of about $464.045 million between the historical year and the projected test year. As the Company failed to adequately support the reasonableness or prudence of cost recovery for a number of these projections the Commission should reject the same.

[23] The Company's assertion that "[s]lowing the installation rate will jeopardize the competitive contract" and "erode the economies of scale" are not adequate replacements for demonstrating cost recovery for this project is appropriate. (McPhail 3 Tr 1741.) As noted above the Company's BCA is flawed and does not provide a basis for finding the Company's cost recovery proposal is reasonable or prudent.

a. Covert plant.[24]

References in the Record: Blumenstock 6 Tr 3514-15, 3519-20, 3592-96 (recommending the Commission approve the Company's proposal); York 6 Tr 3692-93 (recommending cost recovery disallowances).

The Company proposed recovering $21.163 million in the Bridge Period for work that is not covered under normal planned maintenance in the Covert Plant LTSA. (Blumenstock 6 Tr 3514-15, 3519-20, 3592-96.) For the test year it also proposed recovering $9.525 million for Unit 1 and $4.093 million for Unit 3 for extra work not covered under normal planned maintenance in the LTSA. (*Id.*) These amounts are speculative and the Company has not met its burden to demonstrate cost recovery is reasonable or prudent.

The Company indicated that based on historical outage experience there are typically items discovered that are not covered under the LTSA, but which need to be addressed, and argued that the Commission should assume work done on Unit 2 will effectively also be necessary for Units 1 and 3. (*Id.*) Despite these assertions, these amounts are highly speculative, may or may not be incurred, and are dramatically out of line with actual historic costs. (York 6 Tr 3692-93.) Indeed, actual costs associated with this item were $86,688 in 2023 and $1,339,561 in 2024. (Exhibit AB-3 at 22-59.) Despite its explanations the Company has not met its burden to demonstrate it is reasonable to increase cost recovery for these speculative, hypothetical, undetermined future costs by dramatic magnitudes and tens of millions of dollars.

A disallowance would be consistent with the Commission's findings in Consumers' prior electric rate cases, where the Commission agreed "that Consumers' evidentiary presentation on this issue was inadequate." *In the Matter of the Application of Consumers Energy Co*, order of the

[24] ~~This issue is addressed at Blumenstock 6 Tr 3514-15, 3519-20, 3592-96 (recommending the Commission approve the Company's proposal); York 6 Tr 3692-93 (recommending cost recovery disallowances).~~

Public Service Commission, entered March 1, 2024 (Case No. U-21389), p 56. Specifically, the Commission found that the "simple fact that a potential expenditure was included in an exhibit in a previous IRP proceeding is not sufficient to demonstrate the reasonableness and prudence of that expenditure in a rate case, and the support provided on the instant record is insufficient." *Id*. There "Consumers presented no historical data in support of the request," despite the Commission's finding that it was "probable that the company had access to data that could have been used to support this funding request." *Id*. Indeed, in Consumers' last rate case the Commission again found that "with respect to the Covert plant LTSA-extras . . . Consumers has not demonstrated that the company's projected costs are reasonable and prudent." *In the Matter of the Application of Consumers Energy Co*, order of the Public Service Commission, entered March 1, 2025 (Case No. U-21585), p 149. There "the company again failed to provide any historical data to demonstrate that its projected expenditures were reasonable" and, as such, the Commission disallowed "expenditures for both the bridge period and the test year for LTSA-extras at the Covert plant." *Id*.

The Company has not rectified these evidentiary deficiencies here and the Commission should again disallow cost recovery at this time. Again, as the Commission noted in the Company's prior rate case, the Company "may recover reasonable and prudent costs in a future rate case" after the amount actually incurred is known. *Id*. Thus, as the Commission has recognized, by its very nature this cost category consists of amounts set aside for unknown issues that *might* be discovered and are not covered under the LTSA.[25] Considering this context, and the fact that historical annual

[25] As such these potential costs are similar to contingency costs, which the Commission has consistently found are not recoverable. The Commission has "found repeatedly, while allowing for contingency costs may be appropriate in project planning, the inclusion of these costs in customer rates is not reasonable," as it "allows the utility to receive a return of and on those costs to the detriment of ratepayers who may never benefit at all" and "if ratepayers were required to bear this risk, there would be no incentive for the utility to minimize projected contingency costs, but every incentive to inflate them." *In the Matter of the Application of Indiana Michigan Power*

amounts vary significantly from year-to-year with no clear trend, it is neither reasonable nor prudent to approve the Company's significant proposed cost increases. The Commission should therefore disallow Consumers' projected Bridge Period and Test Year capital expenditures for extra work not covered by the LTSA from recovery through customer rates at this time.

b. Zeeland.[26]

References in the Record: Blumenstock 6 Tr 3514-15, 3519-20, 3535-36 3592-97 (recommending the Commission approve the Company's proposal); York 6 Tr 3694-95 (recommending cost recovery disallowances).

The Company requested cost recovery of $2.795 million of capital expenditures in the Bridge Period and $4.275 million in the Test Year for work that is not covered under normal planned maintenance in the LTSA. (Blumenstock 6 Tr 3514-15, 3519-20, 3535-36 3592-96.) As these amounts are speculative and inadequately supported the Commission should disallow cost recovery of the $4.703 million for the bridge period and $0.810 million for the test year.

As with Covert, the Company argued that there are typical items discovered that are not covered under the LTSA, but which need to be addressed. (*Id.*) Also as with Covert, these amounts are speculative projections associated with issues that *might* be discovered during the bridge period and projected test year, without any assurance they will be incurred. Furthermore, the projected costs are significantly out of line with historical actuals. (York 6 Tr 3694-95.) For instance, in 2021 and 2022 these actual costs were approximately $0.5 million, in 2023 they were $15.2 million, and in 2024 the actual cost was negative $191,534.[27] (Exhibit AB-3 at 2-59.) Indeed, the

Co, order of the Public Service Commission, entered April 12, 2018 (Case No. U-18370), p 5. The same rationale applies to these costs, which may never occur.

~~[26] This issue is addressed at Blumenstock 6 Tr 3514-15, 3519-20, 3535-36 3592-97 (recommending the Commission approve the Company's proposal); York 6 Tr 3694-95 (recommending cost recovery disallowances).~~

[27] The Company's assertion that this amount is incorrect because of "a credit to the 2018 LTSA extra work capital expenditure amount" further demonstrates the volatility of these costs, as does

Company acknowledged that "[a]t first glance, the trend in investment has not been consistent." (Blumenstock 6 Tr 3596.) In other words, there is no clear historic trend in the capital expenditures associated with this category. The amounts proposed by Consumers are therefore highly speculative and may or may not be incurred at all. (York 6 Tr 3694-95.)

There is therefore an inadequate basis on which to approve the Company's requested cost recovery. Consumers has not met its burden to demonstrate these projections are reasonable or prudent and, as a result, it is premature to include them in rates at this time. The Commission should therefore disallow Consumers' total proposed capital expenditures for this extra work not included in the LTSA from recovery through customer rates. Once these costs (if any) are incurred the Company can seek cost recovery in a future rate case.

c. Jackson.[28]

References in the Record: Blumenstock 6 Tr 3514-15, 3519-20, 3536-37, 3540, 3592-97 (recommending the Commission approve the Company's proposal); York 6 Tr 3695-66 (recommending cost recovery disallowances).

The Company proposed including $3.472 million of capital expenditures in the Bridge Period and $0.315 million in the Test Year for work that is not covered under normal planned maintenance in the LTSA. (Blumenstock 6 Tr 3514-15, 3519-20, 3536-37, 3540, 3592-96.) As these amounts are speculative and inadequately supported the Commission should disallow cost recovery in this case.

As with Covert and Zeeland, the Company argued that there are typical items discovered that are not covered under the LTSA, but which need to be addressed. (*Id*.) Also as with Covert

its assertions that "LTSA extra work capital expenditure amounts for 2023 and 2024 were $0.497 million and 6 $0.330 million, respectively." (Blumenstock 6 Tr 3592-96.)

[28] ~~This issue is addressed at Blumenstock 6 Tr 3514-15, 3519-20, 3536-37, 3540, 3592-97 (recommending the Commission approve the Company's proposal); York 6 Tr 3695-66 (recommending cost recovery disallowances).~~

and Zeeland, these amounts are speculative projections associated with issues that *might* be discovered during the bridge period and projected test year, without any assurance they will be incurred. Furthermore, the projected costs are significantly out of line with historical actuals. (York 6 Tr 3695-66.) In 2021, the actual cost was $4.2 million, while in 2022 the actual cost was negative $180,921 and in 2023 and 2024, the actual cost was less than $0.5 million. (Exhibit AB-3 at 2-59.)

As such, the Company failed to adequately support its projections and there is no clear historical trend justifying Consumers' proposal. The Company therefore failed to meet its evidentiary burden and the amounts proposed by Consumers are speculative and may or may not be incurred. As a result it is premature to include them in rates at this time. The Commission should therefore disallow cost recovery of Consumers' total proposed capital expenditures for this extra work not included in the LTSA. Once these costs (if any) are incurred the Company can seek cost recovery in a future rate case.

C. Capital Structure and Rate of Return – A reasonable ROE for the Company is 9.50%.[29]

References in the Record: Bulkley 4 Tr 2715–2916 (recommending a 50.75% equity ratio and 10.25% ROE); Bleckman 3 Tr 805–931 (recommending a 50.75% equity ratio and 10.25% ROE); Coppola 3 Tr 2514–2567 (recommending a 9.80% ROE and 50.0% equity ratio); Bandyk 6 Tr 3939–3978 (recommending a 9.22% ROE and 50.0% equity ratio); Megginson 6 Tr 4519–4557 (recommending a 9.75% ROE and 50.0% equity ratio); Lyon 2 Tr 2072–2098 (recommending a 9.77% ROE).

A utility's cost of common equity is the expected return that investors require on an investment in the utility. (Walters 6 Tr 3768.) Investors expect to earn their required return by

[29] This issue is addressed at Bulkley 4 Tr 2715–2916 (recommending a 50.75% equity ratio and 10.25% ROE); Bleckman 3 Tr 805–931 (recommending a 50.75% equity ratio and 10.25% ROE); Coppola 3 Tr 2514–2567 (recommending a 9.80% ROE and 50.0% equity ratio); Bandyk 6 Tr 3939–3978 (recommending a 9.22% ROE and 50.0% equity ratio); Megginson 6 Tr 4519–4557 (recommending a 9.75% ROE and 50.0% equity ratio); Lyon 2 Tr 2072–2098 (recommending a 9.77% ROE).

receiving dividends and through stock price appreciation. (*Id.*) Consistent with the general financial and economic standards set forth in *Bluefield Water Works & Improvement Co v Pub Serv Comm'n of W Va*, 262 US 679 (1923) and *Fed Power Comm'n v Hope Natural Gas Co*, 320 US 591 (1944) a utility's ROE should be sufficient to maintain financial integrity, attract capital under reasonable terms, and be commensurate with returns investors could earn by investing in other enterprises of comparable risk. Considering the current and projected state of the utility industry, the Company's overall risk profile, and the results of several analytical methods which ABATE witness Christopher Walters analyzed for this case, the Company's ROE should be set at no higher than 9.50%.

1. The utility industry's access to capital and the context of the current economic environment indicate the Company's ROE should be reduced.

The Company requests a 10.25% ROE. (Bulkley 4 Tr 2720.) Because this proposal is inconsistent with utility industry trends, access to capital, and the Company's credit strength it should be rejected.

While the Company recommended an increase above its current ROE, authorized ROEs for regulated utilities have declined over the last ten years and have been reasonably stable below 10.0% for roughly the last nine years (indeed, the majority of authorized ROEs have been below 9.7% since 2016, with many being below 9.5%).[30] (Walters 6 Tr 3747–49). During that time the

[30] The Commission has stated that "the fact that other utilities have been able to access capital using lower ROEs, as argued by many intervenors, is a relevant consideration." MPSC Case No. U-18255, 4/18/2018 Order, p 20; see also MPSC Case No. U-20561, 5/8/2020 Order, p 113 (explaining its decision and noting that the intervenors "showed that ROEs—both nationwide and in the Midwest—are trending downward with averages below that in Michigan, without harming the ability of affected utilities to access capital and attract investors").

utility industry's common equity ratios have also not deviated too much from the range of 50.0% to 52.0%. (Walters 6 Tr 3750.)

Moreover, industry credit ratings have continued to improve over the years. (Walters 6 Tr 3751.) In a 2024 Utility Capital Expenditures report, the Regulatory Research Associates noted that "[m]ultiple drivers are expected to elevate utility capital expenditures over the next several years," capex spending is expected to be "higher" reaching $197 billion by 2027, and "[u]tilities have multiple opportunities to finance and support energy investments through mechanisms available within the Inflation Reduction Act and the Infrastructure Investment and Jobs Act of 2021. (*Id.*) (internal citations omitted). Further, capital expenditures for the regulated electric and natural gas delivery utilities have increased considerably over 2023 into 2024, and remain elevated through the end of 2026. (Walters 6 Tr 3752.) Therefore, capital investments for the utility industry continue to stay at elevated levels and are expected to fuel utilities' profit growth into the foreseeable future (*Id.*) This increase in capital investment is enhancing shareholder value and attracting both equity and debt capital to the utility industry. At the same time, while capital markets embrace an increase in capital investments, regulatory commissions must protect customers and ensure service is reliable and rates are reasonable, affordable, and fair. (See *Id.*) Indeed, ignoring the impact of high rates on customers of all classes conversely results in revenue constraints for utilities which impact their financial integrity.

In conjunction with these increased investments, regulated utility equity securities continue to receive robust valuations, indicating that utilities can sell securities at high prices and access equity capital under reasonable terms and conditions at a relatively low cost. (Walters 6 Tr 3753.) Utility security valuations are currently very strong and robust relative to the last several years, meaning utilities have access to equity capital under reasonable terms and at lower costs. (*Id.*;

Exhibit AB-5.) Therefore, given that authorized returns on equity, credit standing, and access to capital have all been robust for utilities over the last several years, even throughout the duration of a global pandemic and economic downturn, it is critical that the Commission ensure utility rates are increased no more than is required to provide fair compensation and maintain adequate financial integrity. See *Hope*, *supra*, 320 US at 591.

The utility industry's relatively strong financial position is further buttressed by the Federal Reserve's (the "Fed") efforts to support the economy to achieve maximum employment and manage long-term inflation at around a 2% level. (Walters 6 Tr 3754.) Specifically, the Fed has implemented procedures to support the economy's efforts to achieve these policy objectives, including lowering the Federal Overnight Rate for securities and engaging in a Quantitative Easing program to moderate the demand in the marketplaces and support the economy. (*Id.*) Currently the Fed is reducing its holdings of Treasury securities and agency debt and agency mortgage-backed securities. (*Id.*) A September 17, 2025, statement by the Fed suggests that economic activity has moderated and inflation remains somewhat elevated, but unemployment remains low. (Walters 6 Tr 3756).

With respect to interest rates, short-term projections suggest that while the market expects current capital costs to remain relatively flat to marginally increase over time, they will maintain levels that are still low by historical standards. (Walters 6 Tr 3757.) For instance, independent projections show that the federal funds rate will decrease while long-term interest rates, as measured by the 30-year Treasury bond, are expected to remain relatively flat. (*Id.*) Moreover, the outlook for interest rates has moderated more recently relative to 2020 and part of 2021, when actual interest rates were in the range of 1.4% to 2.1%. (Walters 6 Tr 3759.) While interest rates were expected to increase drastically from their actual levels in the 2020-2021 period, those same

projections are now flat to declining, which indicates the cost of long-term capital might be near its peak. (Walters 6 Tr 3760).

While continued low interest indicates a positive environment for utilities, credit rating agencies analyses have stressed that rate affordability is an important consideration in assessing utility credit. For instance, Moody's recently explained that regulated utilities' outlook remains "Negative" largely due to increased pricing pressures on customers, specifically explaining that the outlook was due to "increasingly challenging business and financial conditions stemming from higher natural gas prices, inflation and rising interest rates," which in turn "raise residential ***customer affordability issues***, increasing the level of uncertainty with regard to the timely recovery of costs for fuel and purchase power, as well as for rate cases more broadly." (Walters 6 Tr 3762) (emphasis added). Similarly, in its 2025 Outlook report, S&P noted that regulated utilities face continued credit pressure due to elevated capital spending, persistent cash flow deficits (exceeding $100 billion), and increasing physical risks such as wildfires and extreme weather. (Walters 6 Tr 3760.) The S&P further noted that rapid increases in capital spending lead to sustained rate increases which strain customers and rate affordability. (Walters 6 Tr 3761–62.) Finally, Fitch opined that the regulated electric and gas utilities' outlook is deteriorating due to elevated capital expenditure spending that puts pressure on credit metrics. (Walters 6 Tr 3762.) Fitch also notes that "[b]ill affordability concerns for ratepayers continue to persist despite the pull back in natural gas prices and inflationary pressures." (*Id.*) (internal citations omitted). Therefore, S&P, Moody's, and Fitch have all focused on rate affordability as a central factor to support a strong credit standing. In other words, customers must be able to afford their utility bills for utilities to maintain their financial integrity and strong investment grade credit standing.

Lastly, since the beginning of the second half of 2021, the electric utility sector has significantly outperformed the S&P 500, with a total return of 57.47% compared to the market's overall return of 63.13%. (Walters 6 Tr 3764.) The utility sector has been able to deliver positive and relatively stable returns during a period of elevated inflation, rising interest rates, and uncertainty over geopolitical events around the world. (Walters 6 Tr 3765.) Therefore, there is no volatility of utility credit metrics or otherwise a basis for the Company to receive and elevated ROE.

Considering the relative strength of the utility industry's financial position in the immediate and long-term it is inappropriate and unnecessary to increase the Company's ROE, especially to such a dramatically elevated level of 10.25%. It is instead imperative that utility rates reflect the relative stability of utility performance contrasted with the impact of increasing rates on customers of all classes. The Company's proposed increase in its ROE should therefore be rejected and the Commission should instead approve a ROE of no higher than 9.50%.

2. The Company's risk and empirical analyses conducted by ABATE demonstrate that Consumers Energy's ROE should be set at no higher than 9.50%.

a. The Company's level of risk indicates it is a safe, stable investment.

The Company's level of risk is best described by credit rating analysts' reports (Walters 6 Tr 3771.) The current credit ratings for Consumers Energy is A- from S&P and A3 from Moody's. (*Id.*) The Company's outlook from S&P is "Negative" and its outlook from Moody's is considered "stable." (*Id.*) (citation omitted).

Further, S&P noted in its September 2025 report that its "stable outlook on CE reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk." (*Id.*) As stated by S&P, Consumers has a

strong credit profile and ratings, low risk, and benefits from constructive credit support mechanisms and Michigan's existing regulatory framework. (Walters 6 Tr 3772). This provides a clear framework for lowering the Company's ROE when its risk profile diminishes. Consumers' authorized ROE should reflect its actual risk and evolve with its risk profile. The regulatory mechanisms available to the Company clearly insulate it from risk and permit it to earn above its authorized ROE.[31] The ROE approved in this case should reflect those mitigated risks, consistent with the Commission's assertion in Case No. U-21585. This is particularly the case here, where the Company's persistent revenue sufficiencies resulting from projected test year costs indicate Consumers is systematically overprojecting its costs or underestimating its revenues. (Dauphinais 6 TR 3642). Basing the Company's revenue on a historical test year would more accurately reflect the utility's actual earnings and mitigate inflated revenue requirements, although given the above and the analyses below, the Company does not require a ROE above 9.50%.

b. The Company's proposed capital structure is unreasonable, contradicts the Commission's preference, and skews its ROE request.

The Company's proposed 50.75% equity ratio is higher than its current equity ratio, counter to the Commission's directives on this topic, and inconsistent with industry trends. (See Walters 6 Tr 3766.) The Company's request also exceeds the 50.0% level authorized for Consumers' gas division in its recent rate case (Case No. U-21806), which CMS Energy described as "constructive" to investors in a presentation just last month.[32] The Commission should therefore reduce the Company's equity ratio to avoid unnecessarily increasing customer rates.

[31] See also See CMS Energy Investor Meetings November 2025 at 6 (available at https://s26.q4cdn.com/888045447/files/doc_presentations/2025/11/November-2025-Presentation.pdf).

[32] *Id*. at 11.

The Company's proposed equity ratio also exceeds that for the proxy group the Company used to support its ROE recommendation. (*Id.*; see also Exhibit AB-6.) In fact, the Company's proxy group had an average common equity ratio of 40.1% (including short-term debt) and 43.8 (excluding short-term debt) as calculated by S&P Global Market Intelligence and *Value Line*, respectively. (*Id.*) Consumers' proposed equity ratio of 50.75% therefore exceeds that of the proxy group's comparable average equity ratio. (*Id.*)

Moreover, The Company's proposal conflicts with the Commission's clear directives on capital structures. In a most recent example, in Consumers Energy's last electric rate case, Case No. U-21585, the Commission reiterated its preference is a "balanced capital structure" which reflects a balance between investors interests and customer interests. (Walters 6 Tr 3767); MPSC Case No. U-21585, 3/21/2025 Order, p 233. The Company's request 50.75% equity ratio therefore moves in the opposite direction of the Commission's continually stated preference.

The Company's proposed 50.75% equity ratio exceeds the equity ratios of the proxy group and directly contradicts the Commission's preference for the Company to maintain a more balanced capital structure (*i.e.*, 50/50).

c. The Company's proxy group demonstrates a lower ROE is reasonable.

An appropriate proxy group is necessary to determine a reasonable return by considering investments in other firms of comparable risk. (Walters 6 Tr 3772.) The proxy group utilized for ABATE's quantitative analyses is the same group developed by the Company, minus NorthWestern Corporation and TXNM Energy which should not be used in any proxy group analysis because both companies recently announced they were being acquired by other firms. (Walters 6 Tr 3773).

The proxy group developed by ABATE has average credit ratings of BBB+ and Baa2 from S&P and Moody's, respectively. (*Id.*) The BBB+ rating from S&P is one notch lower than Consumers' rating of A- from S&P and the Baa2 rating from Moody's is two notches lower than Consumers' rating of A3 from Moody's. (Walters 6 3774). Similarly, the proxy group has an average common equity ratio of 40.1% (including short-term debt) and 43.8% (excluding short-term debt) as calculated by S&P Global Market Intelligence and *Value Line*, respectively. Although Consumers' credit ratings are comparable to the proxy group, the Company requested equity ratio of 50.75% significantly exceeds the proxy group's equity ratio. (*Id.*) Therefore, ABATE's proxy group is more reasonably comparable to Consumers than that used by the Company and the Commission should reject its requested equity ratio.

d. Reasonable empirical models demonstrate a reasonable ROE for the Company is 9.50%.

In developing a reasonable ROE for the Company, ABATE witness Walters applied the following empirical models to the proxy group described above: (i) a constant growth discounted cash flow ("DCF") model using the consensus of analysts' growth rate projections; (ii) a constant growth DCF using sustainable growth rate estimates; (iii) a multi-stage growth DCF model; (iv) a risk premium model; and (v) a capital asset pricing model ("CAPM"). Considering the results of these analyses—and Consumers' specific risk profile—a reasonable ROE is 9.50%.

i. Constant growth DCF model.

The constant growth DCF model posits that a stock price equals the sum of the present value of expected future cash flows discounted at the investor's required rate of return or cost of capital. (See Walters 6 Tr 3774.) ABATE's constant growth DCF model relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on September 12, 2025. (Walters 6 Tr 3775.) An average stock price is less susceptible to

market price variations than a price at a single point in time, meaning an average stock price is less susceptible to aberrant market price movements, which may not reflect the stock's long-term value. (*Id.*)

ABATE used each proxy company's most recently paid quarterly dividend as reported in *Value Line*. (*Id.*) For dividend growth rates, to attempt to estimate investors' expectations about what the dividend or earnings growth rate will be, and not what an individual investor or analyst may use to make individual investment decisions, securities analysts' growth estimates that are captured in observable stock prices have been shown to be more accurate than growth rates derived from historical data. (Walters 6 Tr 3776.) Therefore, ABATE's growth rate, relied on a consensus, or mean, or professional securities analysts' earnings growth estimates as a proxy for investors' dividend growth rate expectations. (*Id.*) The specific growth rates used are shown in Exhibit AB-7. The average growth rate for the proxy group is 7.22% and the median growth rate is 6.87%. (Walters 6 Tr 3777). As shown in Exhibit AB-8, the average and median constant growth DCF returns for the proxy group for the 13-week analysis are 11.05% and 10.50%, respectively.

It should be noted, however, that the proxy group average three- to five-year growth rates are approximately 77% higher than the long-term projected GDP growth rate of 4.09%.[33] (*Id.*) This makes these ROE estimates much higher than is reasonable as a utility's growth rate cannot exceed the growth rate of the economy in which it provides services in perpetuity, which is the time period assumed by the DCF model. (*Id.*)

[33] Blue Chip Economic Indicators projects a U.S. nominal GDP growth rate of 4.09% over the next 10 years. (Walters 6 Tr 3777–78). This is a reasonable proxy of long-term growth because utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services and can be used as a conservative maximum long-term growth rate projection (*Id.*)

ii. Sustainable growth DCF model.

The sustainable growth rate is determined by the proportion of the utility's earnings that is retained and reinvested in its plant and equipment, which reinvested earnings enhance the earnings base—also known as rate base. (Walters 6 Tr 3778.) The internal growth approach is linked to the percentage of earnings retained within the Company, as opposed to being paid out as dividends. (*Id.*) The payout ratios of the proxy group are shown in Exhibit AB-9. These dividend payout ratios and earnings retention ratios can be used to develop a long-term growth rate driven by earnings retention. (Walters 6 Tr 3779.) The data used to estimate the long-term sustainable growth rate is based on the Company's current market-to-book ratio and on *Value Line*'s three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances. (*Id.*) As shown in Exhibit AB-10, the average and median sustainable growth rates for the proxy group using this internal growth rate model are 5.29% and 4.83%, respectively. A DCF estimate based on these sustainable growth rates is developed in Exhibit AB-11 and produces proxy group average and median DCF results for the 13-week period of 9.05% and 8.85%, respectively. (*Id.*)

iii. Multi-Stage growth DCF model.

The DCF model is intended to represent the present value of an endless series of future cash flows. (*Id.*) In addition to the analyses described above, to accommodate changing growth expectations over time as investments slow or plateau, it is therefore also important to consider a multi-stage DCF analysis that reflects growth rate change over time. (Walters 4 Tr 3780.) In other words, the three- to five-year growth rate projection noted above should be viewed as a long-term sustainable growth rate, but not without considering current market conditions and industry trends, and determining whether the three- to five-year growth outlook is feasible and sustainable. (*Id.*)

The multi-stage DCF model reflects the possibility of non-constant growth for a company over time and reflects three growth periods: (1) a short-term growth period consisting of the first

five years; (2) a transition period, consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year 11 and extending into perpetuity. (Walters 6 Tr 3780-81.) Again, utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which these utilities sell services. (Walters 6 Tr 3781.) As such, nominal GDP growth is a reasonable upper limit for utility sales growth, rate base growth, and earnings growth in the long-run. (*Id.*) Therefore, the U.S. GDP nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility.

As shown in Exhibit AB-12, the average and median DCF ROEs for the proxy group using the 13-week average stock price are 8.62% and 8.21%, respectively. (Walters 6 Tr 3785) Again, the results of the constant growth DCF using analysts' growth rates assume an average long-term growth rate of 7.22%, which is approximately 77% higher than the long-term projected GDP growth rate of 4.09%. (*Id.*) As this is an unsustainable assumption it likely leads to an overstatement in the cost of equity for a low risk regulated utility. As such, more weight should be given to the sustainable growth and multi-stage models of the DCF.

iv. Risk premium model.

This model is based on the principle that investors require a higher return to assume greater risk. (Walters 6 Tr 3786.) This risk premium model is based on two estimates of an equity risk premium: (i) the difference between regulatory commission-authorized returns on common equity and contemporary U.S. Treasury bonds; and (ii) the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields by Moody's for certain relevant periods. (*Id.*)

Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, an estimated range of risk premiums provides the best method to measure the current return on common equity for a risk premium methodology. (Walters 6 Tr 3787.) The risk

premium model therefore assessed the five-year and ten-year rolling average risk premiums over the study period to gauge the variability over time. (*Id.*) These rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle. (*Id.*)

Taking the risk premium result from the method described above, and adding a risk premium over Treasury yields of 5.28% to the projected Treasury Yield of 4.60%, produces an ROE of 9.88%. (Walters 6 Tr 3789) (internal citation omitted). Using A-rated utility bond yield of 5.86% results in a 9.92%. (*Id.*)

Moreover, a weighted least squares ("WLS") regression analysis produces an ROE of 9.85%. (Walters 6 Tr 3794). The standard OLS regression analysis conducted by the Company gives equal weight to every observation in the dataset, which causes it to dilute or overlook structural changes in the relationship. (Walters 6 Tr 3793) The WLS regression analysis conducted by ABATE gives more weight to more recent data, allowing the analysis to adapt more quickly to evolving capital market conditions. (*Id.*) This approach better reflects the current dynamics between interest rates and ERP rather than relying on outdated relationships that may no longer apply. (*Id.*)

v. CAPM model.

The CAPM method of analysis is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. (Walters 6 Tr 3794.) In a well-diversified portfolio, specific risks related to individual stocks can be reduced by balancing the portfolio with securities that offset the impact of firm-specific factors, such as business cycle, competition, product mix, and production limitations. (Walters 6 Tr 3795)

Non-diversifiable risks, on the other hand, are related to market conditions and are referred to as systematic risks. (*Id.*) These risks cannot be reduced through diversification and are considered market risks. Conversely, as indicated above, non-systematic risks, also known as business risks, can be reduced through diversification. (*Id.*) According to the CAPM, the market does not compensate investors for taking on risks that can be diversified away. (*Id.*) Investors are only compensated for taking on systematic, or non-diversifiable, risks. (*Id.*)

The CAPM requires an estimate of the market risk-free rate, the Company's "beta" (which is a measure of systematic risks), and the market risk premium. (*Id.*). The market risk premium is the difference between the expected market return and the risk-free rate. The beta used in ABATE's analysis was based on the current proxy group average and median *Value Line* beta estimates (*Id.*; Exhibit AB-18.) As shown in Exhibit AB-19, the results of twelve (12) different applications of the CAPM range from 8.99% to 10.62%. (Walters 6 Tr 3803.)

e. A reasonable ROE for the Company should therefore be no higher than 9.50%.

Based on these analyses, an appropriate estimate for the Company's current market cost of equity is within the reasonable range of 9.00% to 10.00% (Walters 6 Tr 3805.) This recommended range accounts for the unsustainable growth rates assumed in the constant growth DCF model and more weight given to the sustainable growth and multi-stage models of the DCF. Therefore, based on an objective assessment of Consumers' overall risk profile and the results of these analytical methods, an appropriate ROE for the Company is 9.50%, which is the midpoint of the range produced by these models. (*Id.*)

3. The Company's requested ROE is excessive and unreasonable.

The Company recommends a return on common equity range of 10.25% to 11.25% with a recommended ROE of 10.25%. (Bulkley 4 Tr 2720.) It arrived at these percentages based on its

analyses of several models which it applied to its proxy group. Those models included a traditional CAPM and an empirical CAPM ("ECAPM"), a constant growth DCF model, and a bond yield plus risk premium analysis. (Walters 6 Tr 3807.) As shown below, however, the Company's models use unreasonable inputs which lead to inflated results and a higher ROE. Specifically, Consumers' estimated ROE is the result of the following flaws: (1) its constant growth DCF results are based on unsustainably high growth rates; (2) its CAPM and ECAPM are based on inflated market risk premiums and flawed methodology; and (3) its risk premium model is predicated on an excessive estimated risk premium. (Walters 6 Tr 3808.) As this proposal is excessive and unreasonable given Consumers' actual risk and the flaws in the Company's analyses, the Commission should reject the Company's request.

a. The Company's DCF model analyses are flawed and overstated.

The Company conducted a constant growth DCF analysis using average stock prices over 30, 90, and 180 trading days ending Mach 31, 2025. (Walters 6 Tr 3808). This resulted in an average mean DCF range from 9.05% to 11.31% and an average median DCF range from 9.63% to 10.89%. (*Id.*); see also (Schedule D5, pp 3–5). As ABATE witness Walters points out, these growth rates exceed projected GDP growth and are therefore unreliable. (Walters 6 Tr 3809). Indeed, even the Company's lowest-growth rate scenario is excessive. Growth rates that exceed the growth rate of GDP in the county in which a utility provides goods and services cannot be sustained. (*Id.*) Consumers failed to consider the results of a multi-stage DCF which would have accounted for the expected growth of the U.S. economy. (*Id.*)

As demonstrated by ABATE witness Walters, the average and median results of a multi-stage DCF model are 8.62% and 8.21%, with a midpoint of approximately 8.42%. (*Id.*). The midpoint of the Company's constant growth DCF models is 9.71% and 9.94%. Therefore, after considering the multi-stage model, and removing the highly inflated (and unreasonable) high

growth rate in the Company's DCF model, a DCF-based ROE closer to 9.50% is reasonable, if not generous. (*Id.*)

b. The Company's CAPM analysis is inaccurate and relies on overstated Value Line betas leading to inflated results.

The Company relies on a proxy group average beta estimate of approximately 0.95 based on the average beta from *Value Line*. (Walters 6 Tr 3812.) This represents a 21.1% increase from ABATE's proxy group average Value Line beta of 0.75. The Company's CAPM analysis relies on current *Value Line* betas that are overstated and heavily impacted by the market's fallout, and resulting volatility, due to the global pandemic in 2020-21. (*Id.*) This produced an average CAPM return in the range of 12.17% to 12.18%. (Walters 6 Tr 3807) (citing Schedule D5). This inflated and inaccurate CAPM should be discarded. Moreover, the Company's DCF-derived market risk premiums are based on a market return of approximately 12.58%, which consists of a weighted average growth rate component of 11.15% and weighted expected dividend yield of approximately 1.36%. (Walters 6 Tr 3811). The Company's sustainable market growth rate of 11.15% is far too high to be a rational outlook for sustainable long-term market growth. (*Id.*) This growth rate is nearly three times the growth rate of the U.S. GDP long-term growth outlook of 4.09% and should, therefore, be rejected. (*Id.*)

c. The Company's ECAPM analysis is inherently flawed, inflated, and should be rejected.

The Company's ECAPM should also be rejected. The ECAPM analysis was originally designed to use unadjusted regression betas, yet the Company utilized an adjusted beta as published by *Value Line*. (Walters 6 Tr 3813.) This inevitably inflated the Company's proxy group's average beta estimate range from 0.84 to 0.96.[34] (*Id.*) The end result of using adjusted

[34] Regulatory commissions across the country generally disfavor the use of ECAPM, particularly when an adjusted beta is used in the model. For instance, the California Public Utilities

betas in the ECAPM is an expected return that has been flattened by *two* adjustments, meaning the vertical intercept has been raised twice and the security market line has been flattened twice. (*Id.*) As described by ABATE witness Walters, there is simply no legitimate bases to use an adjusted beta within an ECAPM because it unjustifiably—and materially—inflates a CAPM return for a company with a beta less than one (1), such as Consumers. (Walters 6 Tr 3814–15.) Therefore, the Commission should totally reject the Company's proposed ECAPM and not consider it when determining an appropriate ROE range.

d. The Company's bond yield risk premium analysis and associated regression study is flawed and produced an outlier.

There are several flaws with the Company's risk premium analysis which lead to inflated and overstated results. Most importantly, the Company used an erroneous regression study. (Walters 6 Tr 3816). The Company's analysis is predicated on authorized ROEs as the starting point, but the Company's average BYRP result of 10.59% *exceeds all* the 91 ROEs awarded to electric utilities since 2024 (*Id.*) In addition, the Company's regression framework is not dynamic enough to capture how the relationship between interest rates and the ERP has evolved over time. As described in ABATE witness Walter's testimony, the flaws in the Company's modeling could be corrected using a WLS regression using annual averages and correct inputs. When properly applying a WLS regression analysis, the ROE produced is far below the Company's proposed 10.25% ROE. (Walters 6 Tr 3817).

Commission concluded that "[w]e are not persuaded that ECAPM produces a result that should be considered . . . [a]djusting betas upward *guarantees* a higher ROE." (Walters 6 Tr 3815.) (emphasis added) (internal citations omitted).

Therefore, given these unreasonable inputs which inflate the Company's ROE range, the Commission should reject the Company's ROE recommendation and adopt the more reasonable and accurate ROE proposed by ABATE.

D. Adjusted Operating Income - The Company's proposed O&M expense is unreasonable and should be rejected.

Relative to its adjusted historical test year level of non-power supply O&M expense for 2024 ($663.802 million), in this case the Company has projected these expenses will increase to $804.952 million for the test year, an increase of $141.150 million, or about 21.3% relative to the 2024 historical level. (See Exhibit A-13 Schedule C-5.1.) This projected increase is comprised of inflation adjustments amounting to $21.974 million, and Other Adjustments amounting to $119.176 million. (*Id*.) As this projected increase is inconsistent with the Company's historic O&M expense and its ongoing efforts to limit that expense the Commission should reject cost recovery associated with this projection.

The Company's projection must be considered in the context of its actual historic costs, which show Consumers' actual annual O&M spending has consistently stayed in the range of approximately $640 million to $680 million for various 12-month periods over the last few years. (See York 6 Tr 3675-77.) Indeed, the Commission most recently approved annual O&M expense of just under $660 million for the test year ending February 2026:

TABLE JAY-1

Annual O&M Cost ($000)

Line	Description	Amount (1)	Sources (2)
1	YE Dec 2022	$ 654,549	See Note 1.
2	YE Dec 2023	682,566	See Note 1.
3	YE Dec 2024	663,802	See Note 2.
4	YE Feb 2025	641,572	See Note 1.
5	YE Feb 2026	647,104	See Note 3.
6	Average	$ 657,919	
7	FTYE Apr 2027	$ 804,952	
8	Increase vs. Avg.	22.3%	

Sources and Notes:

[1] Actual cost from U-21870-AB-CE-0173.

[2] Exhibit A-13 (PDD-42), Schedule C-5.1.

[3] Approved cost from U-21870-AB-CE-0173.

Again, in significant contrast to these amounts, here Consumers has requested cost recovery of $804.952 million of annual O&M expense for the projected test year ending April 2027 (*Id.*) This significant deviation from actual historic costs is unreasonable and the Commission should reject the Company's proposal, particularly with regard to the specific areas discussed in more detail below.

1. Distribution O&M expense – electric operations.

The Company requested test year O&M spending in this category of $300.994 million, representing an increase of $54.373 million, or approximately 22% from the actual 2024 spending level. (Exhibit A-13 Schedule C-5.1.) The Company's requested cost recovery for several programs and subprograms within this area is unreasonable and should be rejected.

a. Non-forestry reliability.[35]

References in the Record: Kelly 2 Tr 1047, 1150-52 (arguing the Commission should approve the Company's request); York 6 Tr 3678-81; Durfee 6 Tr 4426-34 (recommending certain cost recovery disallowances).

The Non-Forestry Reliability expense category includes O&M expenses for, among other items, LVD Lines Reliability, HVD Lines Reliability, and LVD Substations Reliability. (Exhibit A-124.) As these cost projections are inadequately supported and drastically above historic actual amounts the Commission should reject the Company's proposal.

The Company's projected O&M expense for these subprograms drastically exceeds the historical 5-year average and historical actuals for 2024 (see York 6 Tr 3675-77):

TABLE JAY-2

Non-Forestry Reliability O&M ($000)[1]

Line	Description	2024 Actual Amount (1)	Projected Test Year Amount (2)	Test Year vs. 2024 (3)	5-year Average (4)	Test Year vs. 5-Yr Avg. (5)
1	LVD Lines Reliability	$ 580	$ 8,000	1280%	$ 574	1295%
2	HVD Lines Reliability	109	891	715%	214	316%
3	LVD Substations Reliability	3,565	5,475	54%	2,964	85%
4	Total	$4,254	$ 14,366	238%	$ 3,752	283%

Source:
[1] Exhibit A-124 (MPK-14).

Further, the Company's Exhibit A-128 shows that these increases are in large part due to "Other Adjustments." Specifically, for the projects listed above, the "Other Adjustments" account for $10.003 million or 99% of the increase from 2024 to the future test year. (See York 6 Tr 3675-

[35] ~~This issue is addressed at Kelly 2 Tr 1047, 1150-52 (arguing the Commission should approve the Company's request); York 6 Tr 3678-81; Durfee 6 Tr 4426-34 (recommending certain cost recovery disallowances).~~

77; Exhibit A-128.) The Company did not demonstrate that cost recovery based on these "Other Adjustments" was reasonable or prudent.

Specifically, the Company's testimony did not specifically describe or show the basis for how it derived these amounts, instead only making vague statements about how the projected test year amounts were determined. (*Id*.; Kelly 2 Tr 1051-57.) For the LVD Substation Reliability category, for instance, the Company's testimony simply comments on reasons why the projected O&M is increasing, rather than describing a basis for the cost estimate. (*Id*.) Indeed, the Company admitted that the "Other Adjustments" column simply reflects the difference between Consumers' historical actual spend and its projected test year spend. (Exhibit AB-2 at 4-5.)[36]

While the Company asserted that Exhibit A-128 "is to illustrate what amount of the Company's projected O&M spending is tied to inflation, particularly so that interested intervenors can see the impact of different inflation rates" and "[a]t no point is my direct testimony trying to specifically support the 'Other Adjustments' column in and of itself," the Company's further testimony lacks the detail necessary to support its projected spending. (Kelly 2 Tr 1151.) First, these "Other Adjustments" lack sufficient transparency and detail on their origin, calculation, and necessity and the Company's additional documentation does not provide an adequate link between the amounts listed under Other Adjustments and tangible, forecasted changes in workload, operational needs, new requirements, or work order volume. The discovery materials referenced by the Company (such as Exhibit A-222 MPK-32) include general assertions regarding increased work or needs, but do not provide the granular, project-level, or workforce-specific evidence

[36] While the referenced discovery response pertains to projected generation costs, it appears the same explanation applies to the Company's projected distribution costs.

required to demonstrate prudency and necessity, particularly where these adjustments contribute substantial incremental costs to base/historical budgets. (Kelly 2 Tr 1151-54.)

Again, the Commission has stated that its "expectation is that the parties will fully document the basis for their test year projections by offering into evidence detailed supporting explanations and underlying assumptions rooted in expected business, financial, and economic circumstances," and "[r]ate applications may not rely on undocumented estimates of future ratemaking expenses and revenue criteria." *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered May 8, 2020 (Case No. U-20561), p 13. Without detailed cost breakdowns—such as itemized changes in activities, mandates, or program needs corresponding to each Other Adjustment—the Commission is left without a clear benchmark to test these costs against historical performance or regulatory standards. Rates must be set on prudent, substantiated forecasts—not on unexplained or vaguely justified adjustments. The Company's approach would result in unjust and unreasonable rates based on claimed cost components that cannot be reviewed with sufficient scrutiny. Thus, for any sub-program or spending category where "Other Adjustments" contribute meaningfully to the proposed increase and the supporting detail is insufficient or ambiguous, the Commission should moderate or disallow recovery until Consumers provides transparent, substantiated, and itemized justification.

For instance, for LVD Lines Reliability O&M, HVD Lines Reliability O&M, and LVD Substations Reliability O&M, the Company claimed it "provided detailed unitized information for these and other O&M sub-programs, illustrating the projected increasing workload that supports the projected increase in spending" in Exhibit A-222. (Kelly 2 Tr 1151-52.) While this exhibit shows projected increasing numbers of "work units" (e.g. projects, work orders, training hours and headcounts) by various subprogram, it does not identify work units for the specific project types

or tasks that are expected to occur in each program, or a granular level of detail with respect to the cost of specific project types. As such, despite the Company's claims, it has not provided adequate supporting materials to meet its burden.

The Company has therefore failed to demonstrate cost recovery for these amounts is reasonable and prudent. As such the Commission should reduce the Company's projected O&M expense by $10.003 million, which is the amount of "Other Adjustments" included in the projections.

b. O&M and metering without service restoration.[37]

References in the Record: Kelly 2 Tr 1059-78, 1132-33, 1138-43, 1152-54 (arguing the Commission should approve the Company's request); Coppola 2 Tr 2048-57 (recommending cost recovery disallowances); York 6 Tr 3681-89 (recommending cost recovery disallowances); Durfee 6 Tr 4429-36 (recommending cost recovery disallowances); Martus 6 Tr 4477-80 (addressing the Company's proposed regulatory deferral mechanism).

This category includes O&M expenses for several subprograms, including projected expenses for a subset of these subprograms including HVD Lines Demand, LVD Substation Demand, HVD Substations Demand, Staking, and Meter Services. (See York 6 Tr 3681-84; Exhibit A-124.) Given the drastic unsupported difference between the Company's actual historic and projected costs the Commission should reject the Company's requested cost recovery.

As set out below Consumers' projected O&M expense for these subprograms drastically exceeds the historical 5-year average and historical actuals for 2024:

[37] This issue is addressed at Kelly 2 Tr 1059-78, 1132-33, 1138-43, 1152-54 (arguing the Commission should approve the Company's request); Coppola 2 Tr 2048-57 (recommending cost recovery disallowances); York 6 Tr 3681-89 (recommending cost recovery disallowances); Durfee 6 Tr 4429-36 (recommending cost recovery disallowances); Martus 6 Tr 4477-80 (addressing the Company's proposed regulatory deferral mechanism).

TABLE JAY-3

O&M and Metering without Service Restoration ($000)[1]

Line	Description	2024 Actual Amount	Projected Test Year Amount	Test Year vs. 2024	5-year Average	Test Year vs. 5-Yr Avg.
		(1)	(2)	(3)	(4)	(5)
1	HVD Lines Demand	$ 898	$ 2,979	232%	$ 790	277%
2	LVD Substations Demand	4,302	6,398	49%	3,720	72%
3	HVD Substations Demand	4,050	5,311	31%	3,177	67%
4	Staking	6,148	13,948	127%	3,999	249%
5	Meter Services	11,165	17,088	53%	9,856	73%
6	Total	$26,564	$ 45,725	72%	$21,542	112%

Source:

[1] Exhibit A-124 (MPK-14).

Neither the Company's testimony nor its workpapers supported such significant increases in O&M spending relative to the historical amounts. (See York 6 Tr 3681-84.)

Rather than adequately justify these significant increases, the Company instead simply provided a high-level description of its approach. (*Id.*; see Kelly 2 Tr 1061-77.) In other cases, instead of describing the basis for its projection, the Company simply stated that the projected spending level is higher than historical amounts because that is what it projects. For instance, for projected HVD Lines Demand spending the Company asserted the projection "was determined based on the projected number of HVD lines work orders that the Company will have to complete in the test year." For LVD and HVD Substations Demand programs, the Company stated it is "increasing the O&M spending in all four substation O&M programs to get onto the nominal cycles provided in the ESR-1 guidelines and clear maintenance backlogs." For staking, the Company asserted that "[s]pending in this subprogram is primarily driven by staking request volume (units) . . . An anticipated volume increase of 7% is included in the test year projection relative to 2024 contract services." (*Id.*) Further, the Company stated its test year projection for

contractor services related to staking requests includes an anticipated unit cost increase and, for Meter Services, the spending amounts were determined by considering purported projected workload, in which Consumers projected a volume of work based on historical data and expected growth from areas like New Business. (*Id*.) In other words, the Company's projections are based on what it projects. This approach does not satisfy the Company's burden to provide "detailed supporting explanations and underlying assumptions rooted in expected business, financial, and economic circumstances" and instead constitutes reliance "on undocumented estimates of future ratemaking expenses and revenue criteria." *In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered May 8, 2020 (Case No. U-20561), p 13.

Beyond these claims, the Company's actual calculations and method for projecting its costs for these subprograms is also deficient. While spending projections are shown across various exhibits (e.g. Exhibit A-128), as noted above those exhibits' supporting data only reflects underlying inputs that do not explicitly show how the Company arrived at its test year projections. (York 6 Tr 3681-84.) For example, while the projected spend for HVD Lines Demand is based on a projected number of work orders, the Company's testimony does not appear to identify the number of historical actual or projected work orders that form the basis of the projection. (*Id*.; Kelly 2 Tr 1061-62.) Similarly, the Company's testimony does not appear to identify the expected volume of work driving the increase in Meter Services projected spending. (*Id*.) Furthermore, the Company's projected 7% increase in the volume of staking requests is directly contrary to historical data showing significant year-over-year volatility, with no apparent trend. (*Id*.)

Again, while the Company claimed that it provided additional support beyond the figures in A-128, this claimed support is insufficient. (Kelly 2 Tr 1152-53.) For staking, for instance, the Company's rates should be set using a transparent, multi-year and substantiated approach for

staking growth projections, rather than relying solely on projections based on temporary or speculative growth factors. Instead, the Company asserted that reliance on a 7% staking growth rate is justified due to anticipated increases from rural broadband expansion and pointed to evidence of year-to-date volumes to reinforce this position. (*Id*.) Simply adopting MISS DIG's statewide growth estimate here fails to reflect the Company's more moderate historical growth absent major one-time infrastructure surges. The Company's year-over-year staking requests have previously demonstrated variability below 7%, and using a potentially atypical high point to project test-year volume risks overstating O&M needs, resulting in customer overpayment. (*Id*.)

Furthermore, if the actual growth is less than forecasted, the proposed refund mechanism will require after-the-fact correction rather than ensuring rates align with projected, most-likely outcomes. A more appropriate growth factor—between Consumers' own historical averages and the statewide estimate—should be used, with additional justification required for any departure from historical norms. Again, Consumers' historic averages demonstrate historic growth in staking requests for Consumers has not consistently reached 7%. While rural broadband may represent a temporary accelerator, the utility's forecast should differentiate ongoing baseline growth from extraordinary, nonrecurring events. Blindly escalating the staking volume at the Company's highest past growth rate is neither reasonable nor prudent. Cost projections should be set on the balance of long-term actual trends, not on optimistic outliers. The Company's approach– relying on short periods of above-trend activity–distorts rate setting when much of the Company's historical spending spanning both routine and high-growth years does not indicated such sustained escalation. If actual enduring changes in activity levels are demonstrated, then more granular evidence (including broadband project pipelines, actual incremental staking volume by project, and projected end dates) should be presented.

Without supporting details the Company's blanket assertions that projections are simply based on increased spending, without supporting details explaining or demonstrating how these figures actually relate to the specific work being undertaken, do not satisfy the Commission's description of the Company's burden. Given its failure to adequately demonstrate its projections are reasonable or prudent, the Commission should not grant cost recovery for the same. As such the Commission should reduce the Company's projected O&M expense for these subprograms by $18.118 million. This is equivalent to removing the "Other Adjustments" for these subprograms shown on Exhibit A-128 (lines 7-9, 11-12) and brings the projected spend more in line with the five-year average.

c. Field operations - training.[38]

References in the Record: Kelly 2 Tr 1087-90, 1153-54 (arguing the Commission should approve the Company's request); York 6 Tr 3684-86 (recommending cost recovery disallowances).

While the Company's five-year average historical costs for this category were approximately $10 million and its 2024 actual costs were $11 million, the Company has here requested cost recovery of $15.8 million. (York 6 Tr 3684-86; Exhibit A-124.) As the Company failed to adequately support this significant increase the Commission should reject this requested cost recovery.

The Company asserted that the expenses for this subprogram were determined based on the number of employees, apprentices, and external candidates, multiplied by the expected hours of training they will receive each year. (Kelly 2 Tr 1089.) Despite this explanation, it is unclear what assumptions the Company made with respect to the new number of employees, apprentices,

[38] ~~This issue is addressed at Kelly 2 Tr 1087-90, 1153-54 (arguing the Commission should approve the Company's request); York 6 Tr 3684-86 (recommending cost recovery disallowances).~~

and external candidates that will actually require training during the projected test year, and whether that projection is reasonable and likely to be accurate. (York 6 Tr 3684-86.) Further, the Company acknowledged that challenges in obtaining the necessary crews can occur, resulting in projects not being completed as planned. (Blumenstock 6 Tr 3566; Stewart 2 Tr 2202, 2236-37.)

The Company also asserted that its projected Training O&M budget is warranted because it supports training for employees at all stages, rather than just onboarding for new hires, and pointed to documentation showing increased total training hours. (Kelly 2 Tr 1153-54.) Despite this claim, the primary concern with the Company's proposal remains that the underlying assumptions used to forecast its projections were not substantiated with specific and transparent data. The Company has referenced historical headcount trends and indicated a general increase, but it has not sufficiently detailed the basis for projected incremental training costs, such as:

- The specific forecasted mix of new versus existing employees requiring additional training in the test year.
- Breakdowns of training into categories (onboarding, annual continuing education, regulatory or safety-driven updates) to discern the principal cost drivers.
- Evidence that the projected expansion in training hours reflects more than inflationary escalation or generalized growth, particularly in relation to planned increases in Electric Operations headcount.

Although the Training O&M subprogram must accommodate mandatory regulatory and safety requirements, the Company must provide granular support for its requested revenue increase, especially when the "Other Adjustments" column in supporting documents drives a significant portion of the proposed increase. Without clear evidence of incremental cost structure beyond historic averages and generalized workforce growth the Company has not met its burden and Commission should not approve the Company's full requested amount. Instead, a moderated approach consistent with documented historical spending trends, supplemented only for substantiated changes, is appropriate.

While employee training is a critical and appropriate expense, ratepayers should only be asked to fund increases in the Training O&M budget that have been fully justified through detailed projections, historic benchmarking, and transparent data disclosure; i.e., where the Company has met its burden to demonstrate its projections are reasonable and cost recovery is therefore prudent. Given the lack of adequate supporting information and detail the Company has failed to meet that burden here. As such the Commission should reduce the Company's projected test year O&M expense by $4.793 million, as shown on Exhibit A-128 (MPK-18), line 21, which adjustment would bring this projected test year spend closer in line with the five-year average.

2. Line clearing O&M expense.[39]

References in the Record: Stewart 2 Tr 1671-1719 (recommending the Commission approve the Company's proposal); Coppola 2 Tr 2057; York 6 Tr 3686-88 (recommending cost recovery disallowances); Bunch 6 Tr 4047-54, 4060 (recommending specific revenue amounts); Duell 6 Tr 4408-10 (recommending revenue amounts).

The Company projected test year spending in this category of $186.684 million, which represents an increase of $76.459 million (69%) from the actual 2024 spending level. (Exhibit A-13, Schedule C-5.1.) Within this category is the Company's proposed Line Clearing Program, including HVD Line Clearing. (See Stewart 3 Tr 2186.) As the Company's projected costs for this program subcategory were not adequately supported the Commission should reject recovery.

The Company projected test year O&M of $11.840 million for the HVD Line Clearing Program despite actual spending on this subprogram averaging roughly $10.550 million from 2020 through 2024. (Exhibit A-170.) Thus, Consumers' projected O&M for this subprogram represents

[39] This issue is addressed at Stewart 2 Tr 1671-1719 (recommending the Commission approve the Company's proposal); Coppola 2 Tr 2057; York 6 Tr 3686-88 (recommending cost recovery disallowances); Bunch 6 Tr 4047-54, 4060 (recommending specific revenue amounts); Duell 6 Tr 4408-10 (recommending revenue amounts).

an increase of about 12% relative to the historical average. This increase is unsupported. (See York 6 Tr 3686-88.) Indeed, contrary to its requested increase in revenue for this program the Company has consistently *underspent* its planned HVD Line Clearing O&M amounts from 2020 through 2024. (Stewart 3 Tr 2195.) Specifically, as the Company's testimony makes clear, Consumers underspent its planned O&M by about 10% from 2020 through 2024, while also successfully clearing its planned number of miles each year. The Company's testimony also demonstrates that on an annual basis through 2030, it expects to continue clearing a similar number of miles of HVD lines each year, using the same number of crews that have been used for several years. (*Id*.) In other words, nothing about the Company's past expenses or efforts, or its projected efforts, demonstrates a revenue increase is justified or reasonable for this program.[40]

As such, considering the Company's demonstrated track record of consistently underspending planned amounts, achieving the planned number of HVD line miles cleared, and utilizing the same number of crews used to accomplish that goal, the Company has not met its burden to demonstrate a revenue increase for this program is warranted. As such the Company's projected test year HVD Line Clearing O&M should be reduced by 10% to historical levels, or $1.184 million.

[40] Indeed, the Company argued that in "the event the Company completes its HVD workplan spending less than the full proposed amount, it will reallocate any net decrease in HVD clearing costs for the test year to the Low Voltage Distribution ("LVD") system." (Stewart 3 Tr 2237; see also Duell 6 Tr 4410.) The Commission should not approve speculative cost recovery based on the assertion that excessive revenue will simply be diverted to another program without any regulatory oversight, particularly where the Company's requested cost recovery for that alternative program is also excessive.

E. Cost of Service, Rate Design, and Tariffs.

1. Rate LED should be modified to permit a limited facilities allowance for incremental distribution investments and the permissible contract lengths thereunder should not be truncated.~~41~~

References in the Record: Connolly 2 Tr 126-28, 132-83, 3 Tr 167, 169-72 (explaining the Company's proposal and noting that ABATE's modification to Consumers' proposal is acceptable); Gray 2 Tr 672-73 (explaining the Company's proposal); Gorman 4 Tr 3173-80 (recommending the Commission approve the Company's proposal); Palmer 6 Tr 3930-37 (objecting to Consumers' proposal and recommending revisions to Rate LED); Dauphinais 6 Tr 3651-57, 3666-69 (explaining ABATE's support of a modified facilities allowance).

a. The Company's proposed limited facilities allowance for Rate LED is reasonable and should be adopted.

The Company proposed offering Rate LED customers a facilities allowance towards the cost of any incremental distribution investments necessary to serve the customer based on the expected sales margins (i.e., the expected contribution toward Consumers' embedded costs) provided by the customer over the initial five years of service. (See Connolly 2 Tr 126-28.) As this proposal is reasonable[42] and would simply extend the same assistance to Rate LED customers as the Company provides to standard primary customers the Commission should adopt this proposal.[43]

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[41] ~~This issue is addressed at Connolly 2 Tr 126-28, 132-83, 3 Tr 167, 169-72 (explaining the Company's proposal and noting that ABATE's modification to Consumers' proposal is acceptable); Gray 2 Tr 672-73 (explaining the Company's proposal); Gorman 4 Tr 3173-80 (recommending the Commission approve the Company's proposal); Palmer 6 Tr 3930-37 (objecting to Consumers' proposal and recommending revisions to Rate LED); Dauphinais 6 Tr 3651-57, 3666-69 (explaining ABATE's support of a modified facilities allowance).~~

[42] The sale margins used in determining the allowance should be limited to the expected system contribution and delivery service revenues of the customer consistent with the Commission's final order in Case No. U-21585. Expected non-energy power supply revenues should not be included. (Dauphinais 6 Tr 3651-52, 3654.)

[43] The Company's additional proposals to update the production capacity charge under Rate LED to be based on the latest MISO Cost of New Entry ("CONE") and to add power factor provisions to Rate LED that generally mirror those approved by the Commission in Case No. U-21585 for Rates GP, GPD, GPTU and EIP are reasonable and should also be approved, as modified in the

The Company's proposal correspondents to the standard Contribution in Aid of Construction ("CIAC") it already offers its standard primary customers. (*Id*.; see Gorman 4 Tr 3174-75 ("Consumers' existing tariffs include an FA for all primary customers larger than 1 MW").) This is an important tool to attract additional load to contribute to the Company's embedded costs. Customers can face significant up-front costs for interconnecting to a utility's distribution system. This proposal would address those barriers in a similar fashion as the approach already offered by DTE Electric Company ("DTE") under its Rate D13. (Dauphinais 6 Tr 3651-57.) Considering that DTE already provides such a mechanism under its own economic development rate, approving such an option for Consumers helps ensure competitive economic development rates in Michigan which attract load under reasonable contract terms that fully cover the Company's incremental cost to serve these customers. In other words, Consumers proposal would help ensure its competitive position with DTE for attracting new large loads while also ensuring additional customers are not subsidizing the load additions and are instead receiving the benefit of the load's contribution to the utility's embedded costs. (*Id*.)

The premise of Rate LED is that it attracts load additions, thus generating sales margins provided by these customers from the system contribution and delivery service charges they pay. (*Id*.) A facilities allowance limited to the sales margins a customer is expected to pay over the first five years of service with Consumers is reasonable to address initial cost barriers to realizing these additional sales margins contributed throughout the term of a Rate LED customer's contract. In

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Company' Rebuttal Testimony. (Dauphinais 6 Tr 3651-52, 3655-57; Connolly 3 Tr 167.) In other words, the Commission should adopt the power factor provisions it approved in Case No. U-21585 for Rates GP, GPD, GPTU, and EIP for Rate LED customers, but should not adopt a 0.909 power factor threshold for determining whether per kVAR charges or credits apply. (*Id*.) The Company agreed with ABATE that the power factor adjustment to Rate LED should be equivalent to the power factor requirements approved for other primary rates. (*Id*.)

other words, as stated above, it would achieve Rate LED's purpose and improve its competitiveness with the economic development rates of other utilities (and replicate the CIAC offered to standard primary customers) while still ensuring the incremental cost to serve the customer is covered and Consumers (and its customers) realize an additional contribution toward the Company's embedded costs. (*Id*.)

b. MNSC's objection to a Rate LED facilities allowance is overstated and unreasonable.

MNSC argued that the proposed facilities allowance could increase costs for other customers if the revenues paid by the LEDR customer do not fully offset the incremental costs of serving that customer. (Palmer 6 Tr 3930-35.) As MNSC's objection is speculative and baseless the Commission should reject the same.

MNSC argued that the "Commission can only conclude that the facilities allowance will not shift LEDR costs to other customers when Consumers can demonstrate that the customer will pay all of its marginal distribution costs despite using five years of distribution revenues to pay for its incremental, dedicated facilities costs, rather than paying for other distribution costs during that time." (*Id*.) As set forth above, the operative premise of Rate LED and the facilities allowance proposal is that Rate LED customers will contribute to Consumers' embedded costs while receiving limited assistance to address up-front interconnection costs in a manner already provided under DTE's analogous economic development rate and Consumers' tariffs for standard primary customers. Indeed, in its application first establishing this rate Consumers explicitly stated that "Consumers Energy will only offer Rate LED if it expects the marginal contract revenues will exceed the expected marginal costs of serving the incremental load," which the Commission recognized when issuing its approval. *In the Matter of the Application of Consumers Energy Co*, order of the Public Service Commission, entered December 22, 2021 (Case No. U-21160), p 3.

MNSC provided no evidence whatsoever in support of its concern or contention that there would be a marginal distribution cost for Consumers to serve a Rate LED customer beyond the cost of dedicated facilities, never mind one which would exceed the remaining distribution facilities charge and standard distribution charge revenues collected form the customer after deducting the customer's facility allowance and the cost for the dedicated facilities necessary to serve the customer. (Dauphinais 6 Tr 3667; see Connolly 3 Tr 171 ("MNSC witness Palmer states that the Company did not base the charge on any cost basis yet and does not provide an alternative solution other than to increase it"); Gorman 4 Tr 3173-76 ("The proposed FA within LEDR is designed specifically to protect Consumers' ability to recover its incremental distribution connection cost from the new LEDR customer" and "Consumers is able to adjust the distribution charge listed in LEDR if the Rate GPD distribution charge is not sufficient for Consumers to recover its incremental distribution or connection costs incurred to serve the LEDR customer").) MNSC's claims is therefore entirely theoretical and baseless.

Furthermore, MNSC's argument does not account for system contribution charge revenues, which provide another source of sales margins that would not exist but for the customer taking service. (*Id.*; see Connolly 3 Tr 169 (explaining that "the distribution charges for LEDR are the same as the distribution charges set for the Company's Large General Service Primary Demand Rate," that "LEDR customers pay for investments made by the Company for incremental distribution facilities required to serve them through a levelized incremental distribution charge," meaning "LEDR customers are paying the same distribution rates as other customers paying embedded cost rates, in addition to the incremental costs associated with their distribution facilities," and that "[o]ther similarly situated customers are afforded a Contribution In Aid of Construction ('CIAC') allowance to cover some or all of the incremental costs of the distribution

facilities to serve them").) Finally, it's important to note that the minimum demand for a customer to take service under Rate LED is 35 MW (35,000 kW).[44] Considering the size of this load, in most cases Rate LED customers will be served at transmission voltage, meaning the only Consumers distribution facilities serving them would be the dedicated distribution facilities constructed to provide service directly from an interconnection with the Michigan Electric Transmission Company, LLC ("METC") transmission system. (*Id.*) Under this arrangement Consumers would not need to make *any* additional investments in distribution facilities that serve other customers and, as a result, the marginal distribution cost associated with the higher demand on the shared distribution system would be zero. (*Id.*; Gorman 4 Tr 3177.)

MNSC's objection to the proposed facilities allowance is therefore baseless. Indeed, regarding any discrepancy between a facilities allowance and actual revenues, the Company explicitly asserted that it "intends to reconcile any differences in actual collections to proposed collections and would include the facilities allowance in those calculations." (Connolly 3 Tr 170.) The Company's proposal is consistent with its treatment of standard service customers as well as the economic development rate already established for DTE. As such the Commission should reject MNSC's objection and adopt the proposed facilities allowance.

c. MNSC's objection to Rate LED's contract length is unreasonable and should be rejected.

MNSC objected to the current allowable Rate LED contract length, which is between 15 and 20 years. (Palmer 6 Tr 3936-37.) As MNSC's objection is unsupported and baseless the Commission should reject the same.

[44] MPSC No. 14 – Electric, Consumers Energy Company, First Revised Sheet No. D-78.10.

MNSC proposed the Commission limit Rate LED contract terms to seven years, asserting that "Consumers has not justified why it should provide substantial rate discounts for such a long time." (*Id*.) First, as the proponent of the change it is MNSC's burden to demonstrate its recommendation is reasonable and prudent, which it is has not done here. *See In re Dmonion Midwest Energy, Inc*, order of the Public Service Commission, entered July 11, 2001 (Case No. U-12342); Case No. U-8020-R, July 9, 1987, Order, pp 16-17.) Instead, MNSC provided absolutely no support for its proposal beyond pointing to other utility tariffs and asserting Consumers did not support the current contract term lengths. The Company should be permitted to negotiate a sufficient term with a Rate LED customer of at least 15 years, as the Commission approved in Case No. U-21160. (See Connolly 3 Tr 171-72 ("A shortened contract length could result in potential stranded assets should a customer decide to cease taking service from the Company at the end of their contract term" as "LEDR is available to customers using 35 MW or greater, which is a significant amount of load" which "could come with significant investment costs in infrastructure to serve that load," meaning that "infrastructure could be stranded should a customer cease taking service from the Company just seven years later").) MNSC's proposal to dramatically lower the maximum allowed term to seven years is unreasonable, entirely unsupported, and should be rejected.

Furthermore, regarding MNSC's concern regarding the length of the "rate discounts," it is important to note that only production cost charges under Rate LED are not at fully embedded cost. (Dauphinais 6 Tr 3667-69.) In other words, Rate LED customers pay for transmission based on Consumers' cost for transmission service, which is ultimately principally based on METC's fully embedded cost for transmission service, and normal fully embedded costs for delivery (distribution) service pursuant to Consumers' standard delivery service rates. (*Id*.) These charges

are not "discounted." Furthermore, while production charges under Rate LED are not based on Consumers' fully embedded costs for production, they *are* designed to fully cover Consumers' incremental fixed production costs and incremental variable production costs to serve Rate LED customers. (*Id.*) Thus, Consumers' other customers do not subsidize the production costs incurred to serve Rate LED customers.

MNSC's objection to the permissible Rate LED contract term is therefore unsupported and baseless. As such the Commission should reject the same and maintain the current tariff provisions regarding permissible Rate LED contract terms.

2. MNSC's proposed change to the Company's allocation of AMI meters is inadequately supported and does not reflect cost causation.[45]

References in the Record: Davis 4 Tr 2672-74, 2702-07 (explaining the flaws in MNSC's proposal); Robertson 5 Tr 3413-20 (recommending the Commission reject MNSC's proposal); Andrews 6 Tr 3826-29 (recommending the Commission reject MNSC's proposal); Palmer 6 Tr 3911-17 (explaining MNSC's proposal).

MNSC recommended the Commission change the Company's current approach to AMI meter cost allocation, which classifies these costs as 100% customer related, to instead allocate 37% of these costs on a customer basis, 17% on a demand basis, and 36% on an energy basis. (Palmer 6 Tr 3914.) As MNSC's proposal is not consistent with cost-of-service principles it should be rejected.

The Company's meter costs are entirely customer-driven and do not have any relationship to customers' particular demand or energy. Every customer, regardless of their demand or energy usage, must have a meter for the Company to measure and provide them service. (Andrews 6 Tr

[45] ~~This issue is addressed at Davis 4 Tr 2672-74, 2702-07 (explaining the flaws in MNSC's proposal); Robertson 5 Tr 3413-20 (recommending the Commission reject MNSC's proposal); Andrews 6 Tr 3826-29 (recommending the Commission reject MNSC's proposal); Palmer 6 Tr 3911-17 (explaining MNSC's proposal).~~

3827-29.) As such, the cost of the Company's meters is caused by the existence of its customers, not the particularly characteristics of their particular energy usage or peak demand. (*Id*.) That these meters are AMI does not alter this reality; it merely reflects an updated means of measuring and communicating usage. Nothing about these meters changes the fact that they are necessary because of, and their costs are caused by, the need to connect customers. (*Id*.) The Commission has consistently approved the Company's approach to classifying meter costs (including AMI meter costs) as customer-related. MNSC provided nothing to justify abandoning this cost-based approach.

MNSC's gestures towards system level energy and demand benefits do not support deviating from allocating these costs in accordance with their causation. First, the fundamental principle of cost allocation is the concept of cost-causation; i.e., customers should be allocated the costs they cause. (*Id*.) Allocating costs in accordance with asserted system benefits, particularly in this context, conflicts with this principle and shifts costs to customers who have nothing to do with their causation based on amorphous assertions regarding general system benefits. (See Robertson 5 Tr 3414-20 ("Ms. Palmer's recommendation to classify and allocate AMI meter costs based on proportional benefits instead of cost causation represents a significant departure from traditional cost allocation practice of allocating costs based on *cost causation* and utilizes a flawed methodology of assigning costs based on benefits").) Furthermore, even if purported AMI meter benefits were to be considered (which they should not), those benefits would be incidental and general, rather than related to actual metering costs. (Andrews 6 Tr 3827-29; Davis 4 Tr 2672-73 ("While AMI meters provide several benefits, the fact remains that the installation and investment in a meter is driven by the need to connect and serve a customer," meaning the "existence of other benefits does not change the fact that the addition of a customer requires a meter" and Consumers'

"weighted customer allocator appropriately captures how customers drive the utilities investment in metering infrastructure").) The purpose and function of these meters are customer-specific; they measure customer consumption and provide for accurate billing. Secondary energy or demand benefits are properly captured in operational savings, not the classification and allocation of the meter costs themselves.

The specific figures regarding which customers cause these meters to be installed, and thus cause these costs, supports this approach. Consumers confirmed that the vast majority of AMI meters are installed by residential customers. Specifically, residential customers have 1,716,384 AMI meters installed, Commercial customers have 233,462 AMI meters installed, and Primary Rate Schedule GP (the only Primary Rate Schedule with any AMI meters) has only 690 meters installed. (Exhibit AB-20.) Thus, the residential class represents 88% of installed AMI meters, Commercial customers represent 11.97% of installed AMI meters, and Primary customers represent only 0.04% of AMI meters installed. (*Id*.) Again, in terms of Primary customers specifically, while 690 of Consumers' industrial customers on Rate Schedule GP use AMI meters, not a single customer taking service under Rate Schedules GPD, GPTU, or EIP uses an AMI meter, meaning they do not cause this cost at all. (*Id*.; Davis 4 Tr 2673-74 ("Less than 0.04% of AMI meters serve primary rate customers but Ms. Palmer's proposed composite allocator for AMI costs would assign 22% of AMI meter costs to primary rate customers").)

Furthermore, even considering the claimed benefits of these meters (which the Commission should not for the purpose of cost allocation), any benefits from AMI meter usage will go to the customers and classes that use them and cannot be attributed across the Company's system generally. (Davis 4 Tr 2673-74 ("AMI meters and the benefits they provide are not new; the Company began to fully deploy electric AMI meters in its service territory nearly 15 years ago

and during that time the Commission has consistently relied on the weighted customer allocator to fairly apportion meter costs amongst customer classes").) ABATE witness Brian Andrews explained as follows (Andrews 6 Tr 3828-29):

> If there are energy savings from the knowledge that an AMI meter provides, then the customer will see immediate savings on monthly bills, via reduced consumption. If a customer uses AMI information to reduce their peak demand, savings could be immediate or long-term. If a customer has a demand charge billing component and they reduce their peak demand, then they will see that savings on their monthly bill. If peak demand reduction is large enough for the overall class, then that customer's class will see a reduced share of allocated costs in future rate cases.

Indeed, Consumers' explained that MNSC's "categorization of the avoided costs from the AMI business case is also oversimplified" as it assumes "for example, that the benefits from 'AMI Induced Conservation & Energy Efficiency' accrue to all customers in proportion to the total energy allocator," which "view provides no consideration or comparison of whether energy use truly captures the realization of the different benefits (e.g. system benefits from lower peak energy usage and the AMI customer's direct energy savings) to customers." (Davis 4 Tr 2673-74.) Further, MNSC proposed "to divide the entire AMI meter cost between these benefits without considering/comparing the cost of a non-AMI meter to calculate the AMI 'premium' incurred to realize those benefits." (*Id*.) Primary customers represent essentially 0% of the AMI meters, meaning they neither cause these costs, nor will they see any benefits from AMI meter usage. (*Id*.) More specifically, Rate Schedules GPD, GPTU, and EIP do not use AMI meters at all, do not cause these costs, and do not realize any benefit from them being used by customers in other classes. Allocating them costs associated with these meters therefore does not reflect cost causation and is neither reasonable nor prudent.

MNSC's proposal would thus not reflect cost causation and would instead introduce subjective weighting in the Company's cost allocation, reduce transparency, and make results

dependent on assumptions about unquantified benefits. This is directly contrary to the principles of cost-based ratemaking. Specifically, MNSC's proposal would shift costs from residential and commercial customers to primary customers without any engineering or economic evidence that those customers cause these costs, while contravening the clear evidence they do not. Maintaining the customer-based allocation ensures fairness and regulatory consistency and aligns cost recovery with its causation. MNSC's proposal would conversely inappropriately shift approximately $59.5 million of AMI meter costs to the primary customer classes which neither cause nor benefit from these costs. As such the Commission should reject MNSC's proposal.

3. MNSC's proposed change to the Company's allocation of distribution costs is inadequately supported and does not reflect cost causation.[46]

References in the Record: McPhail 2 Tr 1301-02; Davis 4 Tr 2669-71, 2684-702 (explaining the flaws in MNSC's proposal); Robertson 5 Tr 3420-24 (recommending the Commission reject MNSC's proposal) Andrews 6 Tr 3829-31 (recommending the Commission reject MNSC's proposal); Palmer 6 Tr 3917-21 (explaining MNSC's proposal).

MNSC proposed the Commission reject the Company's voltage differentiation allocation of distribution costs and adopt an alternative cost allocation. (Palmer 6 Tr 3921.) As MNSC provided no support for the reasonableness of its recommended approach and it does not reflect cost causation the Commission should reject this proposal.

MNSC claimed that increased distributed generation has created bidirectional power flows such that higher voltage customers benefit from or use portions of the lower-voltage system. (*Id*.) This is inaccurate. (McPhail 3 Tr 1753 ("The extent of bidirectional power flow occurring between the [LVD] and [HVD] system is de minimis" and the "distribution substation load data provided

[46] ~~This issue is addressed at McPhail 2 Tr 1301-02; Davis 4 Tr 2669-71, 2684-702 (explaining the flaws in MNSC's proposal); Robertson 5 Tr 3420-24 (recommending the Commission reject MNSC's proposal) Andrews 6 Tr 3829-31 (recommending the Commission reject MNSC's proposal); Palmer 6 Tr 3917-21 (explaining MNSC's proposal).~~

in the Company's response to discovery request U-21870-MNSC-CE-0207 reveals that only 0.39% of total MWh flowed in the reverse direction between LVD Primary (e.g. Voltage 3) and the HVD (46 kV and 138 kV) system").) Indeed, despite making this claim MNSC provided no engineering analysis, empirical data, or system studies to demonstrate that higher voltage customers actually use, depend upon, or benefit from the lower-voltage distribution network. (Andrews 6 Tr 3829-31; Davis 4 Tr 2671 ("The rare occasion when bi-directional power flow occurs does not fundamentally change what has caused/driven the Company to build out and maintain the infrastructure on its LVD system").) The Company's proposed and historic allocation method is instead properly based on physical use of facilities and voltage level of service, which drive these costs. (*Id*.) Specifically, distribution facilities are planned, built, and operated to serve customers connected at specific voltage levels. As such, high-voltage customers are served upstream of the low-voltage system and do not utilize these facilities; meaning they do not cause the associated costs. (*Id*.) The Company's Electric Asset Categorization ("EAC") system improves accuracy by mapping actual plant investments to their voltage level of use. (Hayward 2 Tr 885-88.) Assigning low-voltage system costs to high-voltage customers would assign those high-voltage customers low-voltage system costs they do not cause, thus distorting cost responsibility and creating cross subsidies that violate the cost causation principle. (Andrews 6 Tr 3829-31.)

MNSC provided no support for its assertion that bidirectional power flows from distributed generation provide a basis for revising the cost allocation of the Company's distribution system costs. (Robertson 5 Tr 3414, 3420-24 ("Regardless of any potential bi-directional power flows, higher voltage customers do not *cause* Consumers Energy to invest in low-voltage distribution infrastructure" and MNSC's "recommendation seeks to allocate low-voltage distribution costs to

higher voltage customers based on alleged benefits, instead of cost causation" while MNSC "does not provide evidence to demonstrate or quantify the benefits [it] alleges higher voltage customers might receive from the low-voltage distribution system").) Thus, while it may be theoretically possible for distributed generation to possibly cause limited instances of reverse flow at the local level, neither MNSC nor Consumers provided any evidence that such flows are significant or system-wide. (McPhail 3 Tr 1753 (explaining "the Company does not currently have the capability to produce comprehensive datasets that capture the full extent of bidirectional flows across the entire distribution system" which "limitation is especially pronounced between the LVD secondary (Voltage Level 4) and LVD primary (Voltage Level 3) systems, where downstream customer density is high and devices capable of sensing reverse flow to the LVD primary system are few").) Indeed, Consumers is still developing analytical tools to measure the extent of bidirectional flow. (Exhibit MEC-17.) Until measurable data demonstrates that higher-voltage customers are materially served by lower-voltage assets, the long-established allocation method should remain unchanged. (See Robertson 5 Tr 3423 (explaining that the "acknowledgement by the Company of the *possibility* that power may sometimes flow from lower-voltage to higher-voltage distribution equipment does not constitute evidence that such flows occur" and "even if bi-directional power flows may occasionally flow from lower-voltage to higher-voltage distribution equipment, Ms. Palmer does not provide any evidence regarding the frequency or magnitude of such occurrences to demonstrate the degree to which higher voltage customers might allegedly benefit by receiving power from a DER," nor does MNSC's claim "recognize the fact that bi-directional power flows cause challenges for Consumers when managing the grid").)

MNSC's recommendation is therefore based on nothing but general assertions about potential future effects of distributed energy resources. MNSC provided no quantitative study,

system model, or power flow analysis showing high-voltage customers receive any measurable usage or benefit from lower-voltage facilities, nor has it provided any actual engineering evidence related to the Company's system. (Andrews 6 Tr 3829-31.) Adopting MNSC's proposal would therefore inappropriately shift costs from low-voltage customers which cause them to higher-voltage customers which do not use the low-voltage system. As such MNSC's proposal is inconsistent with cost-causation principles, would contradict the fundamental principle of cost allocation that customers should pay the costs they cause, and should be rejected.

4. MNSC's proposed allocation of distribution battery costs is inadequately supported and does not reflect cost causation.[47]

References in the Record: Davis 4 Tr 2671-72, 2708-12 (explaining the flaws in MNSC's proposal); Andrews 6 Tr 3831-34 (explaining the flaws in MNSC's proposal and the recommending the Commission reject the same); Palmer 6 Tr 3921-22 (explaining MNSC's proposal).

MNSC proposed that the Commission allocate the costs of distribution batteries to all distribution customers, regardless of whether they are served at a voltage level which utilizes or benefits from these batteries. (Palmer 6 Tr 3922.) This recommendation is entirely unsupported and inconsistent with cost-of-service principles and, as such, should be rejected here.

MNSC claimed that these batteries provide system-wide benefits such as capacity deferral, voltage support, and resiliency, and therefore should not be assigned only to low-voltage customers. (*Id*.) This claim was not supported by any engineering or analytical evidence. (Andrews 6 Tr 3831-33.) The Company properly treats and allocates these costs as LVD because the batteries currently in service are physically connected to, and operate solely within, the low-voltage portion

[47] ~~This issue is addressed at Davis 4 Tr 2671-72, 2708-12 (explaining the flaws in MNSC's proposal); Andrews 6 Tr 3831-34 (explaining the flaws in MNSC's proposal and the recommending the Commission reject the same); Palmer 6 Tr 3921-22 (explaining MNSC's proposal).~~

of the distribution system. (*Id*.) Specifically, the batteries are installed specifically to support local circuits, address local reliability or voltage issues, and manage load on low-voltage feeders. (*Id*.) These batteries are not part of the transmission or high-voltage system used by primary customers. (*Id*.) The customers who are served from these circuits (i.e., low voltage customers) are the ones who directly cause these costs and benefit from these assets. (*Id*.) Stated differently, the costs and benefits are localized to the circuits where the batteries are deployed. Allocating those costs to customers who do not physically or operationally use those facilities would violate the fundamental principle of establishing allocating costs in accordance with their causation and is clearly unreasonable.

Indeed, while MNSC claimed that Consumers did not provide evidence that batteries only serve lower-voltage customers, the Company has documented that its distribution batteries are connected at voltages between 8.32 kV and 24.9 kV, which are classified as low-voltage distribution. (See Exhibit MEC-18; Davis 4 Tr 2672 ("The COSS treats distribution-related battery plant the same way it treats other distribution plant assets because they are deployed to serve a similar purpose" and "[c]urrently the only distribution batteries in service are connected to the LVD system which is why they are allocated to LVD customers" and while MNSC witness Palmer "argues that batteries benefit customers across all distribution levels, presumably a reference to her argument on bi-directional power flow, [] those rare occurrences are not what is causing the Company to invest in LVD batteries").) These facilities are deployed to support the electric distribution system at those voltage levels. Thus, as Consumers has demonstrated, these assets are not serving higher-voltage or transmission level customers. Again, in contrast to this straightforward demonstration of the voltages these batteries serve, MNSC provided no quantitative analysis, modeling, or engineering study demonstrating that high voltage or primary

customers cause these costs or receive measurable benefits from the Company's distribution batteries. (*Id*.) MNSC's recommendation is instead based on general assertions about potential system benefits, not on actual data or operational evidence.

MNSC's recommendation is therefore contrary to cost-of-service principles and would result in inappropriate cost shifting from the customers which cause (and benefit from) these costs to customers which do not. Specifically, if battery costs were spread across all distribution customers, primary customers, who do not use these low-voltage assets, would be allocated costs for facilities installed to serve other parts of the system which they do not use. MNSC's proposal would therefore inappropriately violate cost causation principles and creating cross subsidies among classes. As such the Commission should reject its proposal.

F. Other Issues – The Company's proposal to increase IRM spending is unreasonable and should be rejected.[48]

References in the Record: Kelly 2 Tr 1021-28, 1125-26, 1168-69; Myers 2 Tr 1337-52, 1363-67 (recommending the Commission adopt the Company's proposal); Cira-Reyes 2 Tr 1805-09 (expressing concerns with the Company's proposal); Dauphinais 6 Tr 3645-50 (recommending cost recovery disallowances); Evans 6 Tr 4448-53, 4457-58 (recommending cost recovery adjustments).

The Company has again here requested a dramatic increase in its IRM spending for a period beyond the projected test year in this case. As this proposal is unreasonable and conflicts with the Commission's approach to this program to date the Company's request should be rejected here.

Over the Company's past two rate cases the Commission has provided reticent, constrained approval for the Company's IRM, tempered to limit the number of years it may cover as well as

[48] ~~This issue is addressed at Kelly 2 Tr 1021-28, 1125-26, 1168-69; Myers 2 Tr 1337-52, 1363-67 (recommending the Commission adopt the Company's proposal); Cira-Reyes 2 Tr 1805-09 (expressing concerns with the Company's proposal); Dauphinais 6 Tr 3645-50 (recommending cost recovery disallowances); Evans 6 Tr 4448-53, 4457-58 (recommending cost recovery adjustments).~~

the costs included. See *In the Matter of the Application of Consumers Energy Co*, order of the Public Service Commission, entered March 1, 2024 (Case No. U-21389), pp 272-73; *In the Matter of the Application of Consumers Energy Co*, order of the Public Service Commission, entered March 21, 2025 (Case No. U-21585), pp 364-66. In contrast to this approach the Company has here requested the following: (i) adding a Year 3 (corresponding to its proposed projected test year in this proceeding of May 1, 2026 through April 30, 2027) *and* a Year 4 (May 1, 2027 through April 20, 2028) to its Distribution IRM; (ii) approximately quadrupling its annual capital expenditures in the LVD Line Reliability cost category from $68.5 million per year to $276.2 million per year; (iii) adding a new "Repetitive Outages – LVD" cost category with annual capital expenditures of $30.3 million; and (iv) adding a new "Vulnerable Communities" cost category with annual capital expenditures of $30.0 million. (Myers 2 Tr 1349-55.) For the Year 3 corresponding to its projected test year Consumers has requested approval to increase its authorized annual capital expenditures by $266.0 million (308%). (Dauphinais 6 Tr 3645-50.)

These proposals would result in exorbitant rate increases the Company has not demonstrated are reasonable or prudent. Conceptually, where utility revenues are based on projected costs, a limited IRM with a reconciliation component may provide a method of utility accountability for distribution investments necessary to meet urgent and undisputed needs where the investments have been demonstrated to be the most cost-effective approach. (*Id*.) In other words, to the extent the IRM provides for breaking out project and unit costs, providing for stakeholder input and review, requiring refunds to customers for cost recovery provided for authorized investment levels that were not actually achieved by the utility, and "ring fencing" the included authorized distribution investments into different categories to ensure a utility cannot make up for falling short in one category by making above-authorized investments in a different

category, it may not be objectionable. This is only true, however, to the extent the Commission ensures the following: (i) there an urgent and undisputed need for each included investment and Consumers has met its burden to show the investments are the most cost effective way to address the need; (ii) the years authorized for the IRM do not go beyond the projected test year any more than necessary; and (iii) the categories are not defined overly wide, such that Consumers can avoid a necessary investment in a cost category by making up for it with investment in the same category that has a lower degree of need. Without these guardrails the Company's IRM could quickly become a vehicle for unreasonably and greatly expanding distribution investment beyond projected test year periods without demonstrating that investment is necessary or cost effective. (*Id*.)

In this context, the Company's proposals to both significantly inflate cost recovery through the IRM and extend the period over which it recovers those costs well beyond the test year should be rejected. Again, the Company has proposed to essentially quadruple annual capital expenditures in the LVD Line Reliability costs category, which accounts for approximately 78% of the total $266.0 million (308%) increase in proposed annual IRM capital expenditures. (*Id*.) This level of increased annual investment growth raises a serious question with respect to whether the included investments are in fact urgently and indisputably needed and are the most cost-effective way to address needs. The Commission has already addressed this exact concern in Consumers' last rate case in the context of Zonal Health Improvements, stating that "it remains unclear whether the proposed levels of capital investment represent an optimized approach for maximizing customer benefit" and, prior "to approving a 500% increase in capital spending for zonal health between the bridge period and test year, the Commission will want to see more analysis of the most cost-effective opportunities to drive improvement in reliability performance." *In the Matter of the*

Application of Consumers Energy Co, order of the Public Service Commission, entered March 21, 2025 (Case No. U-21585), pp 63-64. The Commission made similar findings with regard to proposed increases for Secondary Wire Conversions ("additional details supporting the benefits of these conversions are necessary prior to approval for inclusion in rate base of such a significant increase in expenditures") and Right of Way Acquisitions. *Id*.

The Commission should maintain this scrutiny and approach to the Company's proposal here. Specifically, as addressed in greater detail above, at a minimum the Commission should reduce Consumers' proposed annual authorized capital expenditure ($276.2 million per year) for the LVD Lines Reliability cost category for Year 3 (twelve months ending April 30, 2027) and Year 4 (twelve months ending April 30, 2028) by at least $108.8 million per year. This would reduce the total annual authorized capital expenditures under Consumers' Distribution IRM for Years 3 and 4 to no more than $243.6 million per year. (Dauphinais 6 Tr 3649-50.)

III. RELIEF REQUESTED

WHEREFORE, ABATE requests the Commission issue an Order adopting ABATE's positions as outlined in its Direct and Rebuttal Testimony, as well as its Initial Brief.

Respectfully submitted,

CLARK HILL PLC

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Date: December 5, 2025

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870 ALJ Jonathan F. Thoits

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF WAYNE)

Lauren K. Degnan, being first duly sworn, deposes and says that on December 12, 2025, she did cause to be served: the ***Association of Businesses Advocating Tariff Equity's Corrected Initial Brief***, as well as this ***Proof of Service***, in the above docket, via electronic mail to the persons identified on the attached service list.

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SERVICE LIST
MPSC Case No. U-21870

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