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June 25, 2025

VIA ELECTRONIC CASE FILING

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

Re: Case No. U-21806 – In the matter of the application of Consumers Energy Company for authority to increase its rates for the distribution of natural gas and for other relief.

Dear Executive Secretary:

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

Sincerely,

CLARK HILL PLC

Stephen A. Campbell

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Stephen A. Campbell

SAC/nab
Enclosures

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 distribution of natural gas and for other relief.	)))))	Case No. U-21806 ALJ James M. Varchetti

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").

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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 bears the burden of demonstrating that its proposed costs and rates are reasonable and prudent. Despite this requirement, Consumers 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 request to base its revenue requirement on projected test year costs which it may or may not incur in a future period. This approach to establishing utility rate revenue consistently results in Consumers collecting more from ratepayers than necessary to satisfy its actual costs and authorized return. The Company also requested a return on equity ("ROE") and equity ratio which are excessive, inadequately supported, and unnecessary. Further, the Company requested cost recovery for numerous capital expenditure and operations and maintenance ("O&M") cost projections which were inadequately supported and unreasonable. In addition, the Company (and the Michigan Public Service Commission Staff ("Staff"))'s recommended class cost of service study ("CCOSS") and rate design would not best align costs with their causation. Instead, both the Company and Staff proposed rates based on a flawed CCOSS, the results of which were then further skewed to allocate even greater costs to high load factor customers. Staff also proposed exacerbating this allocation inequity by spreading the Company's uncollectible costs to the rate classes which clearly and demonstrably do not cause them.

Accordingly, to ensure just and reasonable rates the Commission should reject these proposals and adopt the recommendations set out below. This will ensure Consumers' rates are

reasonable and prudent and that the Company's costs are allocated to customers consistent with the principle of cost causation.

II. ARGUMENT

A. Test Year –The Commission should reject the use of a projected test year and base the Company's revenue requirement on its historic test year.[1]

1. The Commission should reject the Company's use of projected costs as the basis for its revenue requirement.

The Company requested a $248 million revenue increasing in this proceeding based on projected costs in a future 12-month period. (See Consumers Application at 9.) Because setting the Company's revenue requirement based on projected test years routinely results in excessive over-recovery for Consumers, including in seven of its eight most recent rate case filings, the Commission should instead approve a revenue requirement based on the Company's historic test year. Given that Consumers reported a revenue sufficiency for its historical test year in this proceeding, this would eliminate the need for a revenue increase in this case.

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 4 Tr 1585-90 (recommending the Commission base the Company's revenue increase on a projected test year); York 4 Tr 2072-80 (recommending the Commission based on the Company's revenue on historical costs); Veerapaneni 4 Tr 2393-97 (recommending the use of an average of 2023 and 2024 historical data for capital and O&M expense).

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*. That alternative method should be the use of the historical test year amount for that item adjusted for only known and measurable changes to the amount for that item.

Thus, 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 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

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

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.

The fundamental flaw of 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." (See Case No. U-21637, NRDC Comments at 4-5, 12-13.) "Projected 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." (*Id*.) The Attorney General has 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."[3] (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 embodies these flaws. Its assertion that the use of a projected test year does not handicap Staff and intervenors in reviewing Consumers' rate filings is therefore self-serving, incorrect, and repudiated by those same parties. (See Myers 4 Tr 1585-89.)

This is abundantly clear in this proceeding. Here, the Company's use of projected test year expenses as the basis of its requested revenue regularly results in significant revenue increases beyond those necessary to meet the Company's authorized rate of return including, as noted above, revenue sufficiencies in seven of the Company's last eight rate case filings. (See York 4 Tr 2072-80.) Given Consumers' consistent inability to accurately project costs and revenues in a projected test year the Commission should reject its use here, as it violates 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

[3] The Company's claim that "[p]roviding expected spending for a future test year provides a more transparent rate making process" is therefore completely detached from the actual process of intervening in, reviewing, and testifying regarding these proposals. (Myers 4 Tr 1585-89.) Reviewing potential future costs for reasonableness is far more challenging than reviewing "spending after it has already occurred." (*Id*.) The most significant difference is that the former places the risk of excessive recovery on customers for potential action the utility may take in the future, while the latter places it on the utility for actions which it has already undertaken.

"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 instead utilize the Company's historic test year as a more reasonable reflection of Consumers' revenue requirement and costs.

The inherent flaw in using projected test years is that they approve recovery and allow Consumers to begin recovering potential costs before they have been verified as real and prudently incurred, which has significant detrimental impacts on ratepayers.[4] (York 4 Tr 2072-80.) The most important of these impacts is that customers experience excessive rate increases earlier than if the Company had used historical test years. (*Id*.) 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.[5] (*Id*.) This approach does not, therefore, incentivize prudent management within limited revenue recovery approvals; it incentivizes voluminous rate case filings and conjectural cost proposals. The Company is effectively permitted 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*.) Stated differently, this approach permits the Company to collect revenue from its customers for capital

[4] The Company's assertions that "[t]his is the most accurate way to set rates and . . . provides intervenors an opportunity to comment on the Company's plans for spending prior to the dollars actually being spent" are inaccurate and demonstrate the fundamental problem with projected test years. (*Id*.) As demonstrated 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 has effectively acknowledged in opening Case No. U-21637 for discussion on this issue.

[5] 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. (*Id*.) Further, the Company's rampant and consistent revenue sufficiencies demonstrate that the projected test year approach does little to control utility rates and incentivize prudent management.

expenditures or expenses it does not ultimately incur or has not yet incurred when rates are placed into effect. This unreasonably benefits shareholders at the expense of Consumers' customers.

As demonstrated by its historic revenue sufficiencies, this circumstance is prevalent here. Projected test years have allowed Consumers to recover revenue 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*.) Again, 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 required if requested revenue increases were based on historical test years, particularly as rate case schedules are truncated and utility proceedings continue to overlap. 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 that the utility is procedurally encouraged to include in its filing and which will ultimately be collected from customers. (*Id*.) These projected expenditures are not known and measurable; they are instead highly speculative and potentially avoidable. (*Id*.) As noted above this point has been recognized by numerous entities, including the MOAHR.

Customers therefore end up paying costs that are not known and measurable changes from the historical test year, meaning these projected costs are not inevitable or even precisely identifiable in amount and timing. (*Id*.) As demonstrated on the record and further below, many of the capital expenditures and expenses Consumers has attempted to recover in past general rate cases and is attempting to recover in this current proceeding are highly speculative. (*Id*.) These include capital expenditures and expenses that Consumers has not irrevocably committed to make.

Here the Company has reported a revenue sufficiency of approximately $9.4 million for its historical test year. (*Id*.) This means that in that historical test year (calendar year 2023) Consumers received revenues $9.4 million higher than necessary to earn its authorized rate of return during that historical test year. (*Id*.) This continued a consistent trend, as demonstrated by six out of seven of the Company's previous gas rate filings in which it reported a large revenue sufficiency for its historical test year, four of which involved sufficiencies between $17.7 million and $35.3 million. (*Id*.) It is also important to note that the historical test year values are Consumers' reported historical test year values. If these historical test year values were closely examined, they might very well reveal costs that are not properly recoverable in rates. Consumers' actual revenues in excess of its authorized rate of return in its historical test year may therefore have very well been well in excess of the approximately $9.4 million Consumers has reported. (*Id*.) For instance, as discussed further below, Consumers spent nearly $16 million more than forecasted on three Asset Relocation projects in the historical test year, and provided little explanation to support the cost variances. (*Id*.)

Given the detrimental results and inherent flaws in using projected test years the Commission should reject the Company's proposal to set its revenue requirement based on projected test year expenses in this case. The Company's consistent revenue sufficiencies demonstrate that to do so would violate the Commission's responsibility to approve rates that are just and reasonable. The Company's historic test year is instead a more reasonable reflection of Consumers' revenue requirement and costs and does not support a rate increase in this proceeding.

2. If the Commission considers projected costs as the basis for the Company's revenue requirement it must be exacting in ensuring those projections are accurate and the costs will actually be incurred.

If, despite this recommendation, the Commission elects to approve the use of a projected test year it should to the following: (i) be much more diligent in holding the Company to its burden

regarding its support for its projections and the reasonableness and prudence of its cost recovery; (ii) ensure Consumers is irrevocably committed to incur the projected expenses or cannot otherwise avoid them; and (iii) ensure that Consumers' projected investments and expenses are precisely quantified with respect to both amount and the specific quarter in which Consumers will incur these investments and expenses. It is clear from Consumers' historical test year revenues routinely exceeding its authorized return that either questionable projections are not being caught in reviewing the Company's proposals, the Commission has provided too great a benefit of doubt with respect to the projections questioned by intervenors and/or Staff, Consumers is not actually incurring the costs it has projected, or some combination of the three has been occurring. (*Id.*)

The Commission should also examine the following: (i) customer benefits and detriments that have resulted from the use of projected test years; (ii) conditions under which the Commission would reject the use of a projected test year; (iii) categories of expenses/revenues that are uniquely difficult to predict so as to render their inclusion in a projected test year inappropriate; (iv) minimum criteria to reasonably demonstrate a sufficient commitment by the utility to actually incur the expenses it projects; (v) length of time between the end of the historical test year and the beginning of the proposed projected test year; (vi) a method of tracking projections for various costs to determine consistency and extent of over- or under-projection and potential projection guardrails or limits; and (vii) whether the use of a projected test year by a utility should factor into its authorized ROE. While the solicitation for comments in Case No. U-21637 is a good start, as the primary driver of significant annual rate increases this issue requires concentrated and careful consideration.

Unless and until this issue is brought under control Consumers will continue to earn a rate of return higher than that authorized by the Commission to the ongoing detriment of customers.

As such the Commission should take appropriate action here and reject the Company's use of projected test year expenses as a basis for its rate revenue.

B. Capital Structure and Rate of Return – A reasonable ROE for the Company is 9.45%.[6]

A utility's cost of common equity is the expected return that investors require on an investment in the utility. (Walters 4 Tr 2187.) Investors expect to earn their required return by 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 9.45%.

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 896; Bleckman 4 Tr 801.) Because this proposal is inconsistent with utility industry trends, access to capital, and Consumers' credit strength it should be rejected.

[6] This issue is addressed at Bleckman 4 Tr 801–36 (recommending a 50.75% equity ratio and 10.25% ROE), Bulkley 4 Tr 891–1075 (recommending a 10.25% ROE); Coppola 4 Tr 1839–2062 (recommending a 9.75% ROE and 50.0% equity ratio); Bandyk 4 Tr 2410–44 (recommending a 9.24% ROE); Megginson 4 Tr 2524–62 (recommending a 9.75% ROE and 50.0% equity ratio).

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%).[7] (Walters 4 Tr 2166–67). During that time the utility industry's common equity ratios have also not deviated too much from the range of 50.0% to 52.0%. (Walters 4 Tr 2167.)

Moreover, since 2009, industry credit ratings have continued to improve. (*Id.*) 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. (Walters 4 Tr 2170–71) (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 4 Tr 2171.) 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

[7] 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").

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 4 Tr 2172.) 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-6.) 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 4 Tr 2173.) 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 recent statement by the Fed suggest that economic activity is expanding solidly, with solid labor market conditions though inflation remains somewhat elevated. (Walters 4 Tr 2175) (internal citation omitted).

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 4 Tr 2176.) 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 4 Tr 2179.)

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 4 Tr 2180-81) (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 4 Tr 2179.) The S&P further noted that rapid increases in capital spending lead to sustained rate increases which strain customers and rate affordability. (Walters 4 Tr 2180.) 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 4 Tr 2181.) 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 natural gas utility sector has significantly outperformed the S&P 500, with a total return of 70.24% compared to the market's overall return of 39.56%. (Walters 4 Tr 2182.) 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 4 Tr 2183.) 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. 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 9.45%.

2. The Company's risk and empirical analyses conducted by ABATE demonstrate that Consumers' ROE should be set at no higher than 9.45%.

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 4 Tr 2189.) The current credit ratings for Consumers is A- from S&P and A3 from Moody's, and its outlook from both S&P and Moody's is "stable." (*Id.*) (citation omitted).

Further, S&P noted in its August 2024 report that it "expect[s] Consumers Energy Co. . . . to continue to effectively manage its regulatory risk." (*Id.*) It continued that "Michigan's regulatory construct is above average compared with peers," because of the following: (1) a streamlined 10-month rate case process; (2) the use of forward or projected test-years; and (3) mechanisms such as power support cost rider adjustments and natural gas cost rider adjustments that "help the company earn its allowed return on equity . . . and minimize regulatory lag." (*Id.*)

As clearly 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. In its March 21, 2025 Order in Case No. U-21585 the Commission stated that "with increased certainty of recovery of investments for the company and additional derisking, the ROE could be impacted in the future depending on the record evidence in the case." This provides a clear framework for lowering the Company's ROE when its risk profile diminishes. As evidenced above, Consumers' persistent overearning and revenue sufficiencies demonstrate the Company's lower risk and justify a lower ROE. (Walters 4 Tr 2165, 2190, 2222-24.) For instance, the Company's ability to consistently overearn and utilize a projected test year for establishing its revenue requirement reflect a revenue model with little volatility or uncertainty. As Consumers' revenues exceeded its authorized return in seven out of eight recent filings it is evidently operating under conditions of reduced financial risk. (*Id.*) The recovery certainty and derisking described by the Commission is therefore readily apparent here through the mechanisms that provide Consumers stable cost recovery and over-forecasted revenues. These realities should be considered when evaluating whether an ROE reduction is warranted.

Again, Consumers' authorized ROE should reflect its actual risk and evolve with its risk profile. The regulatory mechanisms available to Consumers clearly insulate it from risk and permit

it to earn above its authorized ROE. 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. (*Id*.) 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 9.45%.

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 4 Tr 2184–86.) The Commission should therefore reduce the Company's equity ratio to avoid unnecessarily increasing customer rates. (*Id.*)

The Company's proposed equity ratio also exceeds that for the proxy group the Company used to support its ROE recommendation. (See Walters 4 Tr 2185; see also Exhibit AB-7.) In fact, the Company's proxy group had an average common equity ratio of 46.3% (including short-term debt) and 50.4 (excluding short-term debt) as calculated by S&P Global Market Intelligence and *Value Line*, respectively. (Walters 4 Tr 2186.) Consumers proposed equity ratio of 50.75% therefore exceeds that of the proxy group's comparable average equity ratio. (*Id.*)

Moreover, Consumers' proposal conflicts with the Commission's clear directives on capital structures. Although Consumers settled for an equity ratio of 50.0% "[o]n a non-precedential basis" in its last gas rate case, any movement beyond a balanced capital structure contradicts the Commission's stated preference. MPSC Case No. U-21490, 7/23/2024 Order, Ex. A, ¶ 3. For example, in the Company's last electric rate case, Case No. U-21585, the Commission

reiterated its preference is a "capital structure balanced between debt and equity" which reflects a balance between investors interests and customer interests. MPSC Case No. U-21490, 3/21/2025 Order, p 232. The Company's request 50.75% equity ratio therefore moves in the opposite direction of the Commission's 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). It also is incongruent with the proposed cost of equity. (Walters 4 Tr 2186) (citing an Arkansas Public Service Commission case whereby it recognized a "lower DTE ratio decreases financial risk and decreases the cost of equity").) Therefore, the Commission should approve a permanent equity ratio for Consumers of 50.0%, as consistent with its prior orders.

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 4 Tr 2191.) The proxy group utilized for ABATE's quantitative analyses is the same group developed by the Company, minus NiSource Inc. ("NiSource"), which should not be used in any proxy group analysis because the company is a party to a "transformative transaction" selling off a portion of its holdings in its vertically integrated electric utility company, NIPSCO. (Walters 4 Tr 2191-92.) With the removal of NiSource, and to achieve a more thorough and complete analysis, ABATE also included six additional water distribution utility companies. (Walters 4 Tr 2192.)

The proxy group developed by ABATE has average credit ratings of A- and Baa1 from S&P and Moody's, respectively. (*Id.*) The A- credit rating of S&P is identical to the Company's S&P rating and the Baa1 rating is one notch lower than Consumer's rating of A3 from Moody's.

(*Id.*) Similarly, the proxy group has an average common equity ratio of 46.3% (including short-term debt) and 50.4% (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, Consumers requested equity ratio of 50.75% significantly exceeds the proxy group's equity ratio. (Walters 4 Tr 2193.) 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 9.45%.

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 the Consumers specific risk profile—a reasonable ROE is 9.45%.

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 4 Tr 2193.) 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 March 21, 2025. (Walters 4 Tr 2194.) 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 4 Tr 2195.) 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-8. The average growth rate for the proxy group is 10.03% and the median growth rate is 7.18%. As shown in Exhibit AB-9, the average and median constant grown DCF returns for the proxy group for the 13-week analysis are 13.54% and 10.74%, respectively.

It should be noted, however, that the proxy group average three- to five-year growth rates are approximately 142% higher than the long-term projected GDP growth rate of 4.14%.[8] (Walters 4 Tr 2196.) 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.*)

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 4 Tr 2197.) The internal growth approach is linked to the

[8] Blue Chip Economic Indicators projects a U.S. nominal GDP growth rate of 4.14% over the next 10 years. (Walters 4 Tr 2197). 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.*)

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-10. These dividend payout ratios and earnings retention ratios can be used to develop a long-term growth rate driven by earnings retention. (Walters 4 Tr 2198.) 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-11, the average and median sustainable growth rates for the proxy group using this internal growth rate model are 5.32% and 4.93%, respectively. A DCF estimate based on these sustainable growth rates is developed in Exhibit AB-12 and produces proxy group average and median DCF results for the 13-week period of 8.70% and 8.38%, respectively.

iii. Multi-Stage growth DCF model.

The DCF model is intended to represent the present value of an endless series of future cash flows. (Walters 4 Tr 2198.) 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 2198-99.) 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 4 Tr 2199-2200.) Again, utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the

economy in which these utilities sell services. (Walters 4 Tr 2200.) 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-13, the average and median DCF ROEs for the proxy group using the 13-week average stock price are 9.26% and 8.47%, respectively. (*Id.*) Again, the results of the constant growth DCF using analysts' growth rates assume an average long-term growth rate of 10.03%, which is approximately 142% higher than the long-term projected GDP growth rate of 4.14%. (*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 4 Tr 2205.) 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. (Walters 4 Tr 2205-06.)

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. (*Id.*) 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 5.63% to the projected Treasury Yield of 4.60%, produces a figure of 10.23%. (Walters 4 Tr 2208) (internal citation omitted). Using 3-month and 6-month periods, the results are 9.78% and 9.73% using A-rated utility bonds, respectively, and 9.98% and 9.94% using Baa-rated utility bonds, respectively. (Walters 4 Tr 2209). Again, the Company's current credit ratings from S&P and Moody's are A- and A3, respectively.

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 4 Tr 2210.) 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. (*Id.*)

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. (Walters 4 Tr 2211.) 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-19.) Because these beta estimates are abnormally high and are unlikely to be sustained over the long-term, the analysis also considered the historical average of

the proxy group's *Value Line* betas and included adjusted beta estimates as provided by Market Intelligence's Beta Generator Model, which relied on a five-year period on a weekly basis ending March 21, 2025. Market Intelligence betas as calculated using its Beta Generator Model are adjusted using the Vasicek method and calculated using the S&P 500 as the proxy for the investable market. (Walters 4 Tr 2211–12.) Because the analysis relied on the S&P 500 to estimate the expected return on the investable market, it is consistent to rely on beta estimates that are also calculated using the S&P 500 as the benchmark for the market. (Walters 4 Tr 2212.)

As shown in Exhibit AB-20, the results of twelve (12) different applications of the CAPM range from 9.17% to 11.44%. (Walters 4 Tr 2219.) Because current beta estimates are based on the most recent five years of historical stock returns and volatility, however, they are still heavily impacted by the market fallout in early 2020. (*Id.*) As such, it is appropriate to give primary consideration to the results of a CAPM analyses using long term average *Value Line betas.*

vi. A reasonable ROE for the Company should therefore be no higher than 9.45%.

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 9.90% (Walters 4 Tr 2221.) This recommended range accounts for the unsustainable growth rates assumed in the constant growth DCF model and the irrational assumption that *Value Line*'s current beta estimates are reflective of current investor expectations. 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 9.45%, which is the midpoint of the range produced by these models. (*Id.*)

e. 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 901.) 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 (mean and median), and a projected risk premium analysis. (Bulkley 4 Tr 896.) As shown below, however, the Company's models use unreasonable inputs which lead to inflated results and a higher ROE. Specifically, Consumer's 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 (3) its risk premium model is predicated on an excessive estimated risk premium. (Walters 4 Tr 2224.) As this proposal is excessive and unreasonable given Consumers' actual risk and the flaws in Consumers' analyses, the Commission should reject the Company's request.

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

In conducting its DCF analysis, the Company relied on consensus growth rates published in *Yahoo! Finance* and *Zacks* and individual growth rate projections in *Value Line*. (Walters 4 Tr 2226.) This resulted in an average DCF range from 8.78% to 11.49% and a median DCF range from 8.69% to 11.54%. (*Id.*; see also (Exhibit A-14, Sch D-5, p 4).) The Company also relies on proxy growth rates of 4.80%, 6.05%, and 7.46%. As ABATE witness Walters points out, these growth rates exceed projected GDP growth. (*Id.*) 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 shown in the below table, the average of Consumers Minimum Growth rate and Average Growth rate constant growth DCF is approximately 9.4%:

TABLE CCW-13

Bulkley's Return on Equity Estimates

Description	Bulkley Results[1]		
Constant Growth DCF (Mean)	Low	Mean	High
30-Day Average	8.59%	9.87%	11.30%
90-Day Average	8.79%	10.06%	11.50%
180-Day Average	8.95%	10.23%	11.66%
DCF Average	**8.78%**	**10.05%**	**11.49%**
Constant Growth DCF (Median)	Low	Median	High
30-Day Average	8.48%	9.83%	11.33%
90-Day Average	8.72%	10.05%	11.57%
180-Day Average	8.86%	10.17%	11.71%
DCF Average	**8.69%**	**10.02%**	**11.54%**
	30-Year Treasury Bond Yield		
CAPM DCF-Derived Results	Current Treasury	Near-Term Proj. Treasury	Long-Term Proj.Treasury
Value Line	11.05%	11.04%	11.07%
Bloomberg	10.15%	10.13%	10.20%
LT Average	10.08%	10.06%	10.13%
CAPM Average	**10.43%**	**10.41%**	**10.47%**
ECAPM		**10.56% - 11.32%**	
Risk Premium			
Current 30-Yr Treasury		10.22%	
Near-Term Projected 30-Yr Treasury		10.19%	
Long-Term Projected 30-Yr Treasury		10.35%	
Risk Premium Average		**10.25%**	
Recommended Range		10.25% - 11.25%	
Company Proposed ROE		**10.25%**	

Sources: [1]Bulkley Direct Testimony, page 60.

This average presented by the Company is consistent with ABATE's average and median multi-stage DCF ROEs for its proxy group using the 13-week average stock price, namely 8.71% and 8.46%. (Walters 4 Tr 2227.) 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 9.0% is reasonable. (*Id.*)

ii. The Company's CAPM analysis only relies on a single methodology leading to inflated results.

Consumers relies on a single DCF-derived expected market return to calculate its CAPM and estimate the market risk premiums. (Walters 4 Tr 2228.) The DCF-derived market risk premiums are based on a market return of approximately 12.04%, which consists of a weighted average growth rate component of 10.45% and weighted expected dividend yield of approximately 1.52%. (*Id.*) Notably, the Company's use of a 10.45% market growth rate is nearly *three times* the growth rate of the U.S. GDP long-term growth outlook of 4.14%. (*Id.*) The earnings growth rate of companies within the composite indices (*i.e.*, S&P 500), should be *lower* than the earnings growth rate for the overall economy—not triple the growth rate of the economy. (Walters 4 Tr 2229.) Additionally, Consumers only uses a single model, the DCF, to calculate the expected return on the market and inappropriately includes NiSource in the proxy group. (*Id.*) This leads to a biased, inflated, and inaccurate result. (*Id.*) A more balanced approach that employs multiple methodologies to calculate the CAPM should be used, such as ABATE's method as discussed above.

iii. 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 4 Tr 2230.) This inevitably inflated the Company's proxy group's average beta estimate range from 0.75-0.88 to 0.82-0.91.[9] (*Id.*) The end result of using

[9] 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 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 4 Tr 2233.) (emphasis added) (internal citations omitted).

adjusted 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. (Walters 4 Tr 2231.) 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 4 Tr 2232–33.) Therefore, the Commission should reject the Company's proposed ECAPM and not consider it when determining an appropriate ROE range.

iv. The Company's bond yield risk premium analysis is flawed.

There are several flaws with the Company's risk premium analysis which lead to inflated and overstated results. ***First***, the Company bases its risk premium analysis on the authorized ROEs for *electric* utilities. (Walters 4 Tr 2234.) These results exceed the highest ROE awarded to any electric utility awarded this year. (*Id.*) ***Second***, Consumers significantly overstates the average equity risk premium by using a range of 6.05% to 6.17%. (Walters 4 Tr 2235.) This represents a 54 to 87 basis point increase relative to the 2023 and 2024 average Treasury yields of 4.09% and 4.41%, respectively. (*Id.*; Exhibit AB-15.) An accurate BYRP analysis should incorporate the long-term average equity risk premium of 5.63% over long-term Treasury yields. (Walters 4 Tr 2234.) 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.

C. Capital Cost Recovery – The Company's proposed cost recovery for several capital expenditures is not adequately supported and should be rejected.

The Company proposes adding approximately $1.1 billion in distribution capital investments over the rate case period, including large expenditures for Asset Relocation and the Company's Enhanced Infrastructure Replacement Program – Distribution ("EIRP"). (Fitzhenry 4

Tr 2132; see also Exhibit A-12, Sch. B5.9.) As described in detail below, these proposed capital investments are either unnecessary or not justified and should be rejected.

1. The Company's proposed main replacement expenditures are unnecessary at this time.[10]

The Company is proposing to spend $223 million in 2025 and $236 million in 2026 in it is EIRP. (Fitzhenry 4 Tr 2135–36). This is a significant escalation from the Company's five-year average expenditures on this program of approximately $143 million. (Fitzhenry 4 Tr 2136.) However, the Company's current safety and reliability metrics do not support a such need to dramatically increase expenditures in this program and, for this reason, its cost recovery should be denied by the Commission.

The data provided by the Company reveals that less than 1% (or 0.63%) of its distribution system is comprised of cast iron mains, which are more prone to corrosion and leakage and therefore require replacement. (*Id.*) However, the vast majority (77.8%) of the Company's distribution main leaks in 2024 were the result of issues unrelated to pipeline corrosion failure, to which legacy cast iron mains are particularly susceptible. (*Id.*) Therefore, the Company's stated desire to accelerate replacement is questionable when most of the gas leaks the Company experienced in 2024 were the result of a combination of excavation damage, natural force damage, or equipment failure. (Fitzhenry 4 Tr 2135.)

[10] This issue is addressed at Pascarello 3 Tr 380–473 (recommending full approval of EIRP capital expenditures); Coppola 4 Tr 1876–90 (recommending disallowances for seven EIRP projects and a spending cap of $197 million); Fitzhenry 4 Tr 2135–36 (recommending cost disallowances); Creisher 4 Tr 2728–36 (generally supportive of the Company's EIRP proposal); deLeon 4 Tr 2328–35 (recommending the use of probabilistic risk modeling and cost-effectiveness calculations when selecting EIRP projects).

It also does not appear that there are excessive safety risks present in the Company's distribution main system. In response to discovery, the Company listed the top twenty-five (25) highest risk main segments according to probabilistic risk modeling:

TABLE CTF-4

Top 25 Highest Risk Distribution Main Segments

Project	Plan Year	Rank	Risk Score
BCY2 Ph2	2026	1	28.3
MAC12 Ph6	2025	2	18.3
LIV4 Ph5	2025	3	17.4
LIV4 Ph5	2025	4	14.9
BCY2 Ph2	2026	5	10.0
ROK12 Ph1	2026	6	8.3
MAC11 Ph2	2026	7	7.9
MDL2 Ph1	2025	8	7.8
BCY3 Ph1	2025	9	6.9
BCY2 Ph2	2026	10	6.7
MAC13 Ph6	2026	11	6.6
ROK16 Ph1	2025	12	6.0
LAN5 Ph7	2024	13	5.9
Civic project	2025	14	5.0
LAN12	2026	15	5.0
LAN5 Ph4	2024	16	4.8
LIV4 Ph5	2025	17	4.8
KAL3 Ph8	2026	18	4.7
Civic project	2025	19	4.2
MAC14 Ph2	2025	20	3.3
MAC11 Ph2	2026	21	3.3
LIV4 Ph5	2025	22	3.3
SAG7 Ph1	2026	23	3.2
JAC1	2025	24	2.8
ROK6 Ph8	2024	25	2.8
Average			7.7

Source: Attachment "U21806-AB-CE-0467_Warriner_ATT_1.xlsx" included in Response to Data Request U21806-AB-CE-0467. Attached as Exhibit AB-5 at page 5.

As can be seen above, only eight (8) of the top twenty-five (25) risk distribution main segments have a risk score higher than 7.7. Ten (10) of the projects have a risk score less than 5.0. It also appears that the Company is proposing to replace main segments with risk scores that are

outside the top 100 risk rankings. (Exhibit AB-27.) This extremely low-level of risk for many of the Company's mains reveals that the Company can selectively replace only the mains with the highest risk while continuing to focus on safety and reliability. (Fitzhenry 4 Tr 2137–38.)

Lastly, the Company consistently over-estimates its planned distribution main replacement work. For instance, in 2023, the Company only replaced 108.9 miles of distribution main included in its EIRP even though it projected it would replace 128.0 miles. (Fitzhenry 4 Tr 2138). This over projection resulted in the Company incurring $68.1 million less capital expenditures than anticipated. (*Id.*; see also Exhibit AB-5, pp 6–7.) If a similar pattern emerges in the Company's forecasted test periods in this case, Consumers will spend less than the forecasted values it is requesting. (*Id.*)

Because the Company has not demonstrated a significant increase in EIRP capital expenditures due to the safety and reliability metrics the Company *itself* has provided, as well as the Company previously over-projecting its replacement work in prior cases, the Company's proposal should be rejected.[11] Rather, the Commission should adopt ABATE's alternative recommendation that EIRP expenditures be reduced to average historical level over the past five years of $143 million. (Fitzhenry 4 Tr 2138.) This represents a reduction in $79.4 million in 2025 and $92.1 in 2026 for a total of $171.1 million in savings from the Company's projection.

[11] Staff's recommendation regarding the EIRP was unaccompanied by any review of the Company's safety and reliability metrics relating to natural gas delivery, review of the cause of natural gas leaks in the Company's distribution system, or review of the risk presented from the Company's planned EIRP distribution main replacement segments. (See Fitzhenry 4 Tr 2156-58.) As such Staff's endorsement of the Company's goal of accelerating the replacement of distribution mains should be rejected. The Company's proposed EIRP-Distribution expenditure levels should be reduced to the average historical expenditure level over the past five years ($143 million).

2. The Company has not justified significant variances in its Asset Relocation Program expenditures.[12]

The Company alleges to have incurred capital expenditures of approximately $83.5 million for its Asset Relocation Program during the historical test year. (Fitzhenry 4 Tr 2139; Exhibit AB-5.) This represents a near $11 million increase from its budgeted expenses—a 15.1% variance in cost. (*Id.*) This variance includes projects such as the Prairie Drain for $1.5 million which was never completed, as well as other projects with greater exceeded budgeted amounts. (*Id.*) In 2023, the three biggest asset relocation projects by capital expenditures were the Mound Road Projects, Atlas Iron Belle Trail Project, and 9 Mile Road Eastpointe projects. Collectively, these projects went over budget by $15.8 million, a 132% increase in cost. (*Id.*)

The Company defended the cost variances as related to scope of work changes, unexpected and heavy concrete restoration costs, and erroneous estimates. (Exhibit AB-5.) However, explanations such as limited changes in project scope, additional concrete restoration work, and poor project estimates are not adequate justification for such excessive cost increases, especially for projects that are already in service and considered used and useful. (Fitzhenry 4 Tr 2141.) Although it is unclear if these decisions were the result of poor management, the Company has the burden of proof to prove otherwise. See *Tortora v General Motors Corp*, 373 Mich 563, 569, n 1; 130 NW 2d 21 (1964) (noting the "general rule of evidence, that the burden of proof lies on the person who wishes to support his case by a particular fact which lies more peculiarly within his knowledge, or of which he is supposed to be cognizant") (internal citations omitted). It has failed to do so here.

[12] This issue is addressed at Warriner 2 Tr 30–68 (recommending full approval of cost recovery of Asset Relocation – Civic Improvement costs); Coppola 4 Tr 1864–69, 1903–04 (recommending disallowance of costs as overstated and premature); Fitzhenry 4 Tr 2139=41 (recommending recovery disallowances).

ABATE therefore recommends that the Commission disallow $15.8 million of the Company's request to account for variances and excess capital costs the Company fails to justify.[13]

D. Operations and Maintenance Cost Recovery – The Company's proposed gas operations O&M expense is unreasonable and should be rejected.

The Company is requesting projected test period gas operations O&M expense of approximately $133.6 million, a net increase of $22.3 million over the historical test period. (Fitzhenry 4 Tr 2142). As described in detail below, this proposal is unreasonable and inflated and should be rejected by the Commission.

1. The Company's non-labor inflation factor is unreasonable.[14]

To arrive at its projected O&M expense, the Company utilized non-labor inflation factors of 3.2% for 2024, 2.4% for 2025, and 2.5% for 2026, as published in S&P Global's June 2024 edition of its U.S. Economic Outlook publication. (Fitzhenry 4 Tr 2146.) The Company also used the Consumer Price Index ("CPI") to determine the appropriate non-labor inflation rate. (*Id.*) This methodology should be rejected.

Comparing these proposed rates to the Blue Chip Economic Indicators of the GDP Chained Price Index over the same period (2.4% for 2024, 2.6% for 2025, and 2.3% for the first three quarters of 2026) demonstrates that the Company's figures are inflated for years 2024 and 2026. (Fitzhenry 4 Tr 2146–47.) Moreover, the GDP Chained Price Index is more accurate and

[13] Together, these capital expenditure disallowances reduce the Company's estimated revenue requirement from $7.2 million to $6.2 million, thus reducing its recommended ROE. (Fitzhenry 4 Tr 2141).

[14] This issue is addressed at Rayl 4 Tr 1761 (recommending use of inflation factors of 3.2% for 2024, 2.4% for 2025, and 2.5% for 2026); Coppola 4 Tr 1856 (utilizing 2.4% and 2.5% inflation factors for 2025 and 2026, respectively); Fitzhenry 4 Tr 2146-47 (recommending alternative inflation rates); Bunch 4 Tr 2377–79 (recommending the Commission apply to 2023-2024 historical average costs the non-labor Total Factor Productivity adjustment to inflation for 2025-2026 of 3.29%); Denzler 4 Tr 2455 (applying productivity adjusted inflation factors to Company projections)..

responsive to consumer substitution. (Fitzhenry 4 Tr 2146.) Under this method, a basket of goods and services is updated annually to reflect what consumers are actually buying. If prices of certain goods rise, consumers may switch to cheaper alternatives and the chained price index will reflect that change in buying habits, while the CPI proposed by Consumers will not. (Fitzhenry 4 Tr 2146–47.) The CPI is also heavily weighted by the cost of medical expenses which is inapplicable to utility non-labor inflation. (Fitzhenry 4 Tr 2147.) Lastly, the GDP Chained Price Index has a stronger correlation with the price of gas meters than the Consumer Price Index–Urban. (*Id.*) (suggesting that that the GDP Chained Price Index is more likely an accurate predictor of future costs of gas meters.)

The components the Company used to calculate its proposed inflation factors are therefore unreasonable and deficient relative to the GDP Chained Price Index. As such, the Commission should adopt the adjustments to the inflation factor proposed by ABATE, resulting in a reduction in O&M expense of approximately $355,100. (Fitzhenry 4 Tr 2148.)

2. The Company's proposal to increase Leak Detection and Repair ("LDAR") O&M expenditures is premature and not justified.[15]

The Company is requesting $1.3 million in O&M expense for the projected test year to address a leak backlog in anticipation of the PHMSA implementing new regulations to reduce methane emissions from gas pipelines and storage facilities. (Fitzhenry 4 Tr 2143.) The Company

[15] This issue is addressed at Pascarello 3 Tr 412–14 (recommending that the Commission approve an additional $1.3 million in capital expenditures for anticipated LDAR rules); Pnacek 4 Tr 1610–12, 1699–1703 (recommending that the Commission approve an additional $1.3 million in capital expenditures for anticipated LDAR rules); Martus 4 Tr 2698–2700 (generally supportive of the Company's LDAR proposal other than the regulatory deferral mechanism); Coppola 4 Tr 2004 (recommending disallowance of $1.3 million for LDAR); Veerapaneni 4 Tr 2404 (recommending disallowance of $1.3 million and that the Commission base the spending level for Leak Repair and Survey on 2023 and 2024 average O&M approach); Fitzhenry 4 Tr 2143-44 (recommending cost recovery disallowances).

also requests the ability to defer any test year O&M expenses resulting from the final rule that exceed the requested funding. (Fitzhenry 4 Tr 2144.) Because these rules have not been implemented and compliance timelines have not been set, it is premature for the Company to incur or recover these costs at this time.

The proposed rules, or Leak Detection and Repair ("LDAR"), introduce several key updates to gas system management, including strengthening survey and patrolling mandates, improved performance standards, and modified criteria for grading leaks and repair timelines, among other changes. (*Id.*) The Company stated that PHMSA is proposing deadlines for operators to repair existing gas leaks identified before the new rule takes effect (expected July 2025). These deadlines include requirements that known Grade 2 leaks and any leaks on transmission lines in sensitive areas be fixed by January 2026 and known Grade 3 leaks be fixed by January 2028. (*Id.*) Yet based on new compliance timelines set forth in the most recently amended draft of the LDAR, these dates are no longer applicable to the Company's test period. (Fitzhenry 2 Tr 2144.)

Additionally, historical evidence does not support the Company's assertion that it has a backlog of leaks that need to be promptly addressed. On the contrary, the number of known main and service leaks scheduled for repair in 2023 was well below the historical average. (Fitzhenry 4 Tr 2145.) In particular, the 5,601 known leaks in 2023 were 27% below the average number of main and service leaks over the last five years (2019-2023). This suggests that the number of leaks has been declining, not increasing. (*Id.*) In addition, the Company's leak backlog only contains Grade 3 leaks (the least hazardous leak classification). Grade 1 and 2 leaks (the most hazardous leak classifications) are not included in the Company's leak back log, which also includes false positives. (Exhibit AB-25; Exhibit AB-26.)

ABATE therefore recommends that the Commission deny the Company's request for an additional $1.3 million of O&M expenditures to address leak repairs. As stated above, the number of known main and service leaks has been declining, and the LDAR has not been finalized. (Fitzhenry 4 Tr 2146.) ABATE also recommends that the Commission deny the Company's request to defer any test year O&M expenses resulting from the final LDAR that exceed the requested funding. (*Id.*)

E. Cost Allocation and Rate Design – An appropriate cost allocation method should reflect cost causation and result in an equitable cost recovery method considering filed CCOSSs, gradualism, and the necessity of avoiding rate shock.[16]

1. The Company's proposed cost allocation does not best reflect cost of service.

The preferred CCOSS Consumers proposed in this case would result in increases well above the system average for Rates ST, LT, and XLT, and its proposed revenue apportionment amongst classes would further increase the revenue requirements for those rates even above the level indicated by its preferred CCOSS. (See Exhibit A-16, Schedules F-1.1 and F-2, p 2; York 4 Tr 2080-93.) Given the flaws in the Company's preferred CCOSS and the inequity reflected in its proposed cost allocation the Commission should instead adopt the more equitable and cost-based revenue allocation described below.

[16] This issue is addressed at Geller 4 Tr 1226-35 (setting out the Company's proposed CCOSSs), Exhibit A-16, A-54 through A-57; Smith 4 Tr 1808-10 (objecting to ABATE's proposed revenue apportionment); York 4 Tr 2069-72, 2080-106, 2119-25 (objecting to Staff and the Company's proposed revenue apportionment and setting out ABATE's alternative proposal), Exhibits AB-4, AB-5, AB-21 to AB-25, and AB-27 to AB-28; Krause 4 Tr 2574-78 (objecting to ABATE's recommendation and proposing Staff's revenue apportionment), Exhibits S-6.0 and S-24.0; Rademacher 4 Tr 2596, 2590-92 (objecting to ABATE's recommendation and proposing Staff's revenue apportionment), Exhibit S-6; Revere 4 Tr 2761-68 (objecting to ABATE's recommendation and proposing Staff's revenue apportionment).

The Company's proposed revenue apportionment is based on a CCOSS using a flawed Average & Peak ("A&P" or "P&A") cost allocation method (discussed further below), and would shift cost recovery from the Residential, GS-3, and Rate XXLT rate classes to Rates ST, LT, and XLT even above the inflated cost apportionment proposed by that flawed CCOSS (*Id.*):

TABLE JAY-3

Consumers' Preferred CCOSS (Version 2) vs.
Proposed Revenue Apportionment ($000)

Line	Rate Schedule	Delivery Revenues at Current Rates[1] (1)	Increase / (Decrease) to Reach Cost of Service[2] Amount (2)	Percent (3)	Index (4)	Consumers Proposed Increase / (Decrease)[1] Amount (5)	Percent (6)	Index (7)
1	Residential[3]	$1,110,994	$201,968	18.2%	1.13	$195,779	17.6%	1.10
2	GS-1[3]	172,968	14,530	8.4%	0.52	16,171	9.3%	0.58
3	GS-2[3]	131,566	2,882	2.2%	0.14	7,432	5.6%	0.35
4	GS-3[3]	28,958	2,184	7.5%	0.47	1,037	3.6%	0.22
5	ST	34,864	11,149	32.0%	1.99	11,814	33.9%	2.11
6	LT	27,199	7,080	26.0%	1.62	7,765	28.5%	1.78
7	XLT	30,204	7,334	24.3%	1.51	7,923	26.2%	1.64
8	XXLT	10,129	882	8.7%	0.54	87	0.9%	0.05
9	Total	$1,546,883	$248,008	16.0%	1.00	$248,008	16.0%	1.00

Sources and Notes:
[1] Exhibit No. A-16 (SAS-1), Schedule F-2, page 2.
[2] Exhibit No. A-16 (SMG-2), Schedule F-1.1.
[3] Proposed revenues include incremental late payment revenue totaling $498,000 from WP-SAS-2.

The Company's proposed cost allocation therefore fails to reflect cost of service principles by starting with a flawed CCOSS and then further exacerbating the inequitable allocation resulting therefrom by shifting even more costs to Rates ST, LT, and XLT. For the reasons set out in more detail below, the following more accurately reflects cost causation as well as an equitable approach

to revenue recovery considering the Company's CCOSSs, gradualism, and the necessity of avoiding rate shock (York 4 Tr 2080-2104):

TABLE JAY-4

Alternative Revenue Apportionment ($000)

Line	Rate Schedule	Delivery Revenues at Current Rates[1] (1)	Consumers Proposed Increase / (Decrease)[1] Amount (2)	Percent (3)	Index (4)	ABATE Proposed Increase / (Decrease) Amount (5)	Percent (6)	Index (7)
1	Residential[2]	$1,110,994	$195,779	17.6%	1.10	$200,560	18.1%	1.13
2	GS-1[2]	172,968	16,171	9.3%	0.58	16,171	9.3%	0.58
3	GS-2[2]	131,566	7,432	5.6%	0.35	7,432	5.6%	0.35
4	GS-3[2]	28,958	1,037	3.6%	0.22	3,192	11.0%	0.69
5	ST	34,864	11,814	33.9%	2.11	8,681	24.9%	1.55
6	LT	27,199	7,765	28.5%	1.78	5,154	18.9%	1.18
7	XLT	30,204	7,923	26.2%	1.64	5,195	17.2%	1.07
8	XXLT	10,129	87	0.9%	0.05	1,624	16.0%	1.00
9	Total	$1,546,883	$248,008	16.0%	1.00	$248,008	16.0%	1.00

Sources and Notes:

[1] Exhibit No. A-16 (SAS-1), Schedule F-2, page 2.

[2] Proposed revenues include incremental late payment revenue totaling $498,000 from WP-SAS-2.

This approach effectively tempers the inflated Rate ST, LT, and XLT increases proposed by the Company and its flawed cost allocation method by using the results of the Company's Version 3 CCOSS (utilizing an Average & Excess ("A&E" or "AED")) cost allocation method, discussed further below) to guide rate design and balance the interests of high and low load factor customers. As such it results in a more equitable distribution of the claimed revenue deficiency and makes a gradual but meaningful movement toward cost of service while also ensuring that no class receives an increase greater than 1.6 times the system average. (*Id.*) This approach more accurately reflects cost-causation on the Company's system than strict adherence to the P&A

method while still embodying the Commission's preference to recognize a volumetric component in allocating demand-related costs. (*Id*.) Thus, utilizing the Version 3 CCOSS to inform and guide how revenue responsibility should be apportioned through the revenue allocation and rate design in this case reflects a more equitable and cost-based revenue apportionment than proposed by the Company or Staff. (*Id*.)

This approach is consistent with the Commission's method of allocating costs in DTE Gas Company ("DTE")'s recent rate case, in which the Commission adopted Staff's proposed rate design which was informed by both the Company's P&A CCOSS and its Alternate CCOSS, with the objective of moving toward a more rational distribution of revenue responsibility, particularly for the transportation rate schedules. *In the Matter of the Application of DTE Gas Co*, order of the Public Service Commission, entered November 7, 2024 (Case No. U-21291), pp 235-36. Specifically, the Commission noted Staff's explanation that while it was not advisable to switch to the Alternate COSS for all cost allocation at that time, "as a stopgap, Staff has used the additional COSS, as modified for Staff's adjustments [] as a guide to how revenue responsibility should be shifted between transportation schedules" and thus "[t]he alternate COSS helps to 'guide the appropriate increases amongst the transportation class schedules.'" *Id*. Thus, in that case "DTE Gas's proposed allocation method for distribution mains, the A&P method, was approved," but "Staff's use of the alternate COSS to guide transportation class rate design" was also "approved separately from the allocation issue." *In the Matter of the Application of DTE Gas Co*, order of the Public Service Commission, entered February 27, 2025 (Case No. U-21291), p 13. The Commission therefore took the approach of approving the Company's proposed allocation method, but also approved Staff's Alternate CCOSS as a "stopgap" to guide how revenue responsibility

should be shifted between transportation schedules, without that Alternative CCOSS being directly utilized. *Id*.

The proposed revenue apportionment reflected above in Table JAY-4 takes this same approach to establish an equitable cost allocation which reflects cost of service and gradualism and avoids rate shock. In other words, utilizing Consumers' Version 3 CCOSS to guide rate design in this case would move classes toward a more rational and equitable revenue allocation based on a more accurate measure of class cost of service. (York 4 Tr 2080-2104.) It also reflects the Company's rate design objectives. Consumers indicated that its rate design goals are establishing rates that promote efficient use of the gas system and energy efficiency, establishing rates that promote a favorable business climate, and designing rates to provide the Company with a fair opportunity to collect its revenue requirement. (Smith 4 Tr 1786.) Moreover, while representing a significant and meaningful reduction in the Company's proposed increases for Rates ST, LT, and XLT (even though those increases would still be above the system average increase), this more equitable approach would have an immaterial impact on other customer classes. Specifically, it would move residential revenues halfway between the level indicated by the Company's Preferred CCOSS and its Version 3 CCOSS which, at the Company's claimed revenue deficiency, would equate to a difference of roughly $0.23 per Residential customer per month. (York 4 Tr 2080-2104.) To the extent the Commission approves a lower revenue increase than the amount requested by Consumers the impact would be even less,[17] while still representing millions of dollars in lower increases for Rate ST, LT, and XLT customers (although those increases would, again, still be above the system average).

[17] For example, if the Commission approves two-thirds of the Company's requested increase, the impact would be about $0.16 per Residential customer per month. (York 4 Tr 2080-2104.)

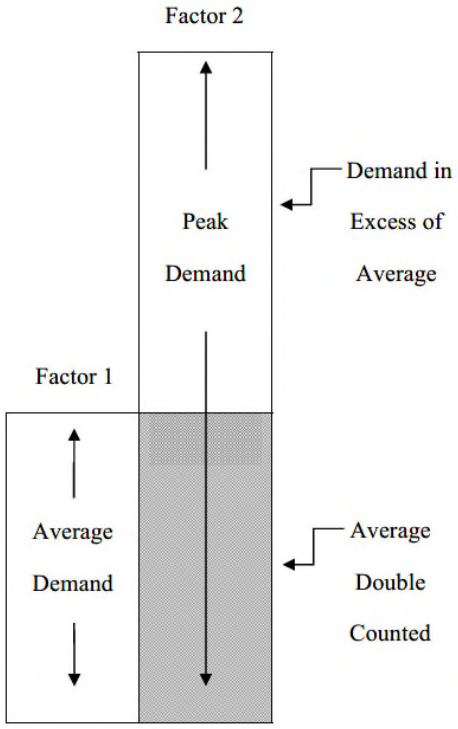
The cost allocation proposed above therefore better reflects Consumers' cost of service reflected in its Version 3 CCOSS (as discussed further below) and results in a more equitable revenue apportionment guided by gradualism and the necessity of avoiding rate shock. The Commission should therefore reject the Company's preferred CCOSS and instead adopt the cost allocation method proposed above.

2. The Company's preferred CCOSS is flawed and does not best reflect cost causation.

As noted above, the Company's preferred CCOSS utilizes the P&A cost allocation method. (See York 4 Tr 2089-2104.) This approach allocates costs by weighing two system load characteristics: the Design Day Demand allocator (weighted by 1 minus the system load factor) and the Average Demand (or annual volume) allocator (weighted by the system load factor). (*Id*.) More generally, this cost allocation method allocates costs to customer classes based on the Company's system costs to provide service at its average annual volume, and at peak demand. (*Id*.) The Commission has previously approved this approach based on its findings that "there are sound reasons for allocating some portion of demand related costs on the basis of non-peak throughput." *In the Application of Consumers Energy Co*, order of the Public Service Commission entered July 31, 2017 (Case No. U-18124), p 114. Specifically, the Commission explained that a "gas distribution system has to produce both peak day service and off-peak service to be economically viable," that "[p]eak day load alone is insufficient to pay for the cost of building the plant," and "[t]o focus only on the peak demand services that the system provides completely ignores how the system operates every other day of the year, when customers still expect the safe, reliable delivery of natural gas." *Id*. In short, the Commission has found that a reasonable cost allocation should reflect the Company's cost of providing service on both peak days and for average demand.

While the P&A method reflects both peak day service and average demand, it does so in a way which redundantly allocates costs based on average demand twice: once in the Average Demand component and again in the Design Day Demand component. (York 4 Tr 2095-97.) This is demonstrated below in Diagram 1, which sets out how the P&A method allocates costs based on Average Demand (Factor 1) and Peak Demand (Factor 2) (see *Id.*):

Peak and Average Method



Peak and Average =

(LF x Factor 1) + (1 – LF) x Factor 2

As illustrated above, during the two-step process of calculating the P&A factors, the first of which is to determine the Average Demand component, the double counting of Average Demand occurs in the next step of the process, where each class' contribution to the system's Peak Demand is determined. In this second step, the P&A method considers the entire Peak Demand, including the Average Demand for a second time. (*Id.*)

Thus, the flaw with the P&A method is that the second component incorporates the first, resulting in a double counting of Average Demand on the peak design day. (*Id*.) As explained by the Pennsylvania Public Utility Commission June 22, 2021 Opinion and Order in Case No. R-2020-3018929, "mains costs are allocated under the P&A methodology based, in part, on Average Demand, and, in part, on the total Peak Demand," although "average demand is included in the average demand component and in the peak demand component, which includes average demand." (See York 4 Tr 2096-98.) Thus, as reflected in the Company's preferred CCOSS, "due to residential customers having temperature-sensitive demand and corresponding low-load factors, double--counting average demand understates the residential cost of service while overstating the cost of service of more efficient gas users." (*Id*.) The Missouri Public Service Commission has similarly found that "the P&A method initially allocates average costs to each class, but then, instead of allocating just the excess of the peak usage period to the various classes to the cost causing classes, the method reallocates the entire peak usage to the classes that contribute to the peak." (*Id*. (internal citations omitted).) Thus, "the classes that contribute a large amount to the average usage of the system but add little to the peak, have their average usage allocated to them a second time," meaning "the Peak and Average method double counts the average system usage, and for that reason is unreliable." (*Id*.) The Minnesota Public Utilities Commission also rejected the P&A method in favor of the Average & Excess method ("A&E") (discussed further below and utilized in Consumers' Version 3 CCOSS) in 2021, also citing the double counting issue:

> Minnesota Power articulates reasonable grounds – based in concerns for equity, efficiency, and cost causation – for favoring the Average & Excess classification method over the Peak & Average method. Both methods recognize that average demand and peak demand warrant consideration. The choice to use peak demand in excess of average demand mitigates the double-counting problem associated with the Peak & Average method. [See *In the Matter of the Application of Minnesota Power*, order of the Minnesota Public Utilities Commission, entered February 28, 2023 (Docket No. E-015/GF-21-335), p 53.]

The P&A method therefore contains an inherent flaw by allocating Average Demand costs twice. An appropriate manner of recognizing and correcting the duplicate allocation of the P&A method is the A&E cost allocation method reflected in Consumers Version 3 CCOSS,[18] which was adopted instead of the P&A method in the Pennsylvania, Missouri, and Minnesota decisions described above. (See York 4 Tr 2080-2101.) This approach recognizes that, as the Commission has explained, a "gas distribution system has to produce both peak day service and off-peak service to be economically viable" without redundantly allocating costs based on Average Demand during both steps of the allocation determination. As such it properly and more reasonably reflects cost causation principles considering the Company's costs to meet both average annual and peak demand.

3. The Version 3 CCOSS and the A&E method utilized therein correct the flaws in the A&P method and should be used to guide revenue apportionment in this case.

The A&E method is similar to the P&A method in that they both include a component based on average demand that is weighted by the utility's system load factor. (York 4 Tr 2093-96.) Both methods therefore satisfy the Commission's findings that "there are sound reasons for allocating some portion of demand related costs on the basis of non-peak throughput," a "gas distribution system has to produce both peak day service and off-peak service to be economically viable," and "[p]eak day load alone is insufficient to pay for the cost of building the plant." *In the*

[18] While Staff asserted that the A&E method does not appear in the June 1989 version of the NARUC Manual, it acknowledged that the methods mentioned include the coincident demand method, the non-coincident demand method, the P&A method, and "some modification or combination of the three." (Krause 4 Tr 2575.) The A&E method is such a modification as it uses non-coincident demand in the calculation of the peak demand component of the allocation factor, as described below. (See Exhibit AB-28 at 24-25.)

Application of Consumers Energy Co, order of the Public Service Commission entered July 31, 2017 (Case No. U-18124), p 114.

Both methods also provide a measure of each class's peak demand; however, the two methods differ in the approach to determining and allocating costs related to the demand component. Specifically, as explained above, the demand component of the P&A allocator reflects each class's contribution to system peak day demand (i.e., coincident peak demand), which *again* includes average demand for a second time in the allocation determination. The peak demand in the A&E allocator, however, only reflects the difference between each class's NCP demand and average demand (i.e., demand in excess of average demand), and as such does not suffer from the inherent flaw of double counting the average demand like the P&A method. (York 4 Tr 2093-96.) Stated differently, under the A&P method average demand is counted in both the average and peak demand components of the allocation, while in the A&E method average demand is only considered in the average demand component of the allocation, not *again* in the peak demand component of the allocation. (*Id*.) The A&E method therefore properly identifies customer classes' distinct contributions to average and peak demand and allocates revenue responsibility based on the utility's costs to meet each. Stated differently, it assigns greater cost responsibility for excess demand to gas deliveries that are more variable due to weather sensitivity or other factors. This is more reflective of cost-causation, as the excess main capacity for serving demand above average usage is built and held in reserve to meet the demand of weather-sensitive loads that spike on a peak day.

The Company confirmed that this method better reflects cost causation than the P&A method. Specifically, it has explained that the A&E method is both reasonable and makes some improvements to the P&A method because, as the P&A method calculates peak demand inclusive

of average demand volumes, while the A&E method only considers the amounts of each rate class's peak demand over and above its average demand, the "more granular approach of the A&E method avoids double counting the average demand volumes in the A&P methodology." (Exhibit AB-1 at 11; Geller 4 Tr 1234-35.)[19] As such, again, the A&E method allocates costs in part based on the Company's need to provide average service throughout the year, but when allocating costs related to peak day service it does so by distinguishing between the amount of capacity needed to serve base or average load, and the amount of capacity needed to serve peak demand that exceeds average demand. (York 4 Tr 2093-96.) Relative to the P&A method, the A&E method therefore more closely reflects how Consumers incurs costs to design the system and how it is actually used by various customer classes. As such it produces a cost allocation which is more equitable, fair, and reasonable, and which more accurately reflects cost-causation on Consumers' gas system than the P&A method.

This is particularly the case here, where Consumers designs its system based on the peak (i.e., not average) demands of its customers, including the hour of maximum demand. (York 4 Tr 2089-93.) The Company must build its system to meet its peak day design requirement, meaning the total maximum daily load for all natural gas customers that Consumers would expect to serve under the most extreme cold weather conditions. (*Id.*; see Exhibit AB-2.) Thus, while the Commission has asserted that "[t]o focus only on the peak demand services that the system provides completely ignores how the system operates every other day of the year, when customers

[19] The Company's disputed issue chart filed in this case notes that it does not disagree with the recommendation to "replacing the current Average and Peak allocation with an Average and Excess Demand ('AED') allocation because it prevents double counting of peak day volumes and better reflects cost causation principles by recognizing the variability in load between customer classes." (Case No. U-21806, Filing No. 216 (May 14, 2025), Consumers' Table of Disputed Issues at 7.)

still expect the safe, reliable delivery of natural gas," the flip side of that focus is also true; i.e., if Consumers only designed its system to meet average demand it would not be able to serve customers when demand exceeded that average. While the Company must serve average demand, its system capacity is therefore ultimately designed to meet system peak demand. (*Id*.) Specifically, the Company explained that its "natural gas system is designed so that the Company can provide continued service during times of peak demand on the system." (Exhibit AB-1 at 1.) Further the Company's "[o]perational objectives include . . . maintaining deliveries to customers throughout the entire year, including design peak day conditions," and in designing its system "the Company would not use a customer class load factor to determine the facilities required." (*Id*. at 5.) Instead, the Company confirmed it doesn't design its system to meet average demand, instead emphasizing the need to meet peak demand. (*Id*. at 1-3.) In addition, the Company acknowledged that "it seems possible that an asset designed to just meet average demand could face challenges in providing reliable service if demand exceeds the average" and "it seems reasonable that depending on demand, not all distribution main capacity may be required to meet that demand on a non-peak day." (*Id*. at 8.)

The Company's system is therefore actually designed to accommodate peak day demand. Capacity planning requires ensuring sufficient supply under extreme and potentially dangerous cold conditions, which also permits the Company to serve its customers under all other conditions when load is less than the design day demand requirement. (York 4 Tr 2089-93.) Contrarily, if main capacity was designed only to meet average demand the Company would not be able to provide firm service on days when demand exceeds the average. As such, it is clear that peak demand drives main capacity costs. (*Id*.) These capacity costs are fixed, meaning once capacity is

installed the costs are set and do not change depending on the amount of gas flowing through the system. (*Id.*) ABATE witness Jessica York provided an illustrative example:

> [C]onsider an example in which Consumers serves two customers with the same Design Day Demand requirements from identical distribution mains (i.e., same material, diameter, installed cost). However, one customer's annual throughput is twice as much as the other's. Thus, the demand-related cost to serve each customer is the same. However, each customer would be allocated a different amount of those capacity costs if an annual throughput allocator is used. Specifically, the customer with greater annual throughput (i.e., the higher load factor customer) would be allocated a greater share of capacity costs than the other customer. The use of a throughput allocator effectively penalizes the higher load factor customer for its more efficient utilization of the installed distribution main capacity. This is contrary to the objective of setting rates based on sound cost-causation principles. [(*Id.*)]

The Company's investment in its distribution system is therefore primarily driven by the need to meet peak demand, rather than solely average demand. Stated differently, the evidence provided by Consumers makes clear that peak demand is the load characteristic that drives investment in capacity to provide safe, reliable firm service to customers on the peak day and all other days throughout the year. (*Id.*) While this would indicate that the most appropriate cost allocation method would focus on peak demand, the Commission has stated that "[t]o focus only on the peak demand services that the system provides completely ignores how the system operates every other day of the year, when customers still expect the safe, reliable delivery of natural gas." The Commission should therefore adopt a cost allocation method which reflects average demand without redundantly weighting that factor twice when also considering peak demand, which is the primary cost driver for Consumers' system investment. As set out above the A&E cost allocation method allocates costs based on customer classes' average demand using a partial energy-weighted method, while also more accurately allocating costs based on customer classes' contributions to the Company's peak demand, which is the factor driving its costs.

While the Company objected to ABATE's proposal to use the Version 3 CCOSS to inform an equitable revenue apportionment, that objection is therefore contradicted and undercut by its

own assertions, as well as its own proposed revenue allocation. Specifically, Consumers claimed that ABATE's proposal involved shifting revenue between classes without a supporting cost basis. (Smith 4 Tr 1808-10.) As explained above, ABATE's proposed revenue apportionment is supported by the Version 2 and Version 3 CCOSSs and uses them to guide and inform an equitable revenue apportionment in this case considering cost of service, gradualism, and rate shock. This is the exact approach proposed by Consumers (and Staff, as discussed further below) in this proceeding through their various rate stability adjustments and breakeven point maintenance. Further, as noted above, Consumers explicitly stated that the allocation method for the Version 3 CCOSS used to inform ABATE's proposed revenue apportionment uses a "more granular approach" than the P&A method in the Version 2 CCOSS, and that it is both reasonable and makes some improvements to the P&A method. (Geller 4 Tr 1234-35; Exhibit AB-1 at 11.) The Company's objection is therefore misplaced and contradicted by its own acknowledgments.

Further, as noted above, the Company asserted that its rate design objectives include establishing rates that promote efficient use of the gas system and a favorable business climate. In addition to more accurately reflecting cost causation and equitably allocating revenue responsibility, ABATE's recommended revenue apportionment would best accomplish those objectives. This is particularly the case here, where Consumers' preferred CCOSS would result in exorbitant increases for large customers and its proposed revenue apportionment would exacerbate that impact to an even greater extent. Energy rates continue to represent a significant portion of large customers' operational costs. Large energy intensive customers, such as ABATE members, are aware of the rates and methods used to allocate utility costs in Michigan and other jurisdictions. (York 4 Tr 2088-89.) Remaining competitive within their industries and across the jurisdictions in which they operate necessarily requires these customers make investment decisions based on

that knowledge. (*Id*.) Adopting CCOSS results which do not accurately reflect cost of service and proposed cost allocations which further skew cost allocations to assign even greater levels of cost to these customers than other jurisdictions hinders Michigan's ability to competitively attract and maintain these industries. Thus, it is important to note that other jurisdictions such as Georgia, Manitoba, Missouri, and Pennsylvania have adopted cost allocation methods that more accurately measure each class's cost of service than the P&A method.[20] (*Id*.) By contrast, the Company (and Staff)'s proposed cost allocation(s) run counter to its own objectives.

[20] The A&E method specifically has been adopted at various times by utility commissions across the country, demonstrating its effectiveness in accurately allocating costs. See *In the Matter of the Advice Letter No. 1923*, order of the Colorado Public Utilities Commission, Docket No. 23AL-0243E, C24-0352 (May 15, 2024) (upholding a prior determination to utilize the Average & Excess method for cost allocation); *In re: Interstate Power and Light Company*, order of the Iowa Utilities Board, Docket No. RPU-2023-0002 (September 17, 2024), p 47 (explaining " it is important to allow a utility to explore what options it believes are appropriate for cost allocation" and approving the utility's proposal "to modernize its CCOSS consistent with the changes in its generation portfolio" by utilizing "the traditional AED method for fossil fuel plant generation, as has consistently been the standard"); *In re Hawaiian Electric Co, Inc*, order of the Hawaii Public Utilities Commission, Docket No. 3705 (June 26, 1981) ("The AED method allocated production demand costs on the basis of each class' average demand weighted by system load factor and the peak demand in excess of weighted average demand. In our opinion, this method distinguishes between the cost to serve the average demand and the cost to serve the excess demand. The AED method recognizes such cost-related factors as class and system load factors, diversity of demand, and peak class demand" and "the AED method is reasonable and an equivalent form of this method has been used and approved by this commission for all Hawaiian Electric Company, Inc., HELCO, and MECO rates cases," leading the Hawaii PUC to conclude that "the AED method is the most reasonable and appropriate demand cost allocation since it considers the greatest amount of variables regarding load characteristics including demand, energy use, load factor, and diversity and results in the allocation of system demand costs to the various classes of service which exhibit wide variation in load character"); *In re Potomac Elec Power Co*, order of the District of Columbia Public Service Commission, Formal Case No. 912 (August 20, 1992), *Application of Gulf States Utilities Co*, order of the Texas Public Utility Commission, entered July 13, 1984 (Docket No. 5560), p 99 (adopting the A&E method and explaining it "gives emphasis to both demand and energy considerations"); *Application of Virginia Electric and Power Co*, Report of Commission Chief Hearing Officer, Case No. PUR-2018-00167 (May 8, 2019) (approving the A&E allocation methodology which Dominion Energy stated it had used in every rate proceeding for the Virginia jurisdiction since 1972); see also Ark Code Ann § 23-4-422(b)(2)(B)(i) (directing that for electric utilities production demand costs must be allocated to each customer class pursuant to the average and excess method).

The Commission should therefore utilize the Company's Version 3 CCOSS to guide and inform the revenue spread and rate design in this case, as it did in Case No. U-21291. This approach would more accurately reflect cost-causation on the Company's system than the Company (and Staff)'s preferred CCOSS and proposed revenue apportionment(s) while also satisfying the Commission's preference to recognize a volumetric component in the allocation of demand-related costs and reflecting a more rational and equitable revenue apportionment.

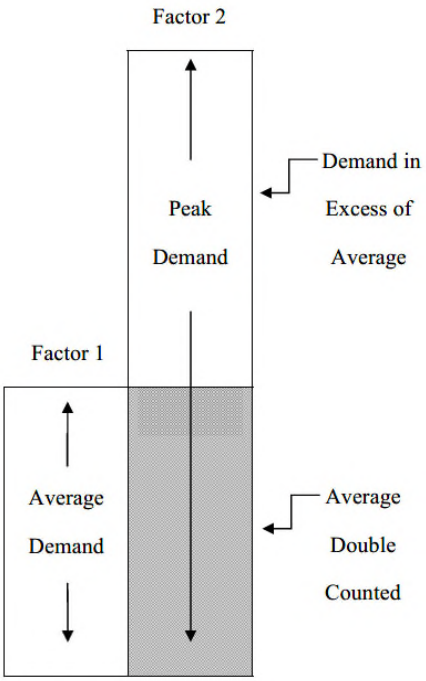
4. Staff's objections to using the Version 3 CCOSS to guide a reasonable revenue apportionment are misplaced.

While ABATE is not recommending the Commission adopt the A&E method in this case, Staff recommended strict adoption of the P&A method as incorporated into its own proposed rate design. In doing so Staff incorrectly claimed that the P&A method does not double count average demand when allocating excess demand costs and the A&E method would allocate costs in a way that does not reflect customers' average use of the system. (Krause 4 Tr 2574-78; Revere 4 Tr 2761-64.) As neither of these points is correct the Commission should disregard Staff's objections.

First, regarding Staff's assertion that "the claimed 'double-count' does not exist," as demonstrated above and determined by multiple additional public utilities commissions, it is a fundamental element of how the P&A method allocates costs. (See Revere 4 Tr 2761-64.) Indeed, despite Staff's protestations, it acknowledged that the "peak" element of the P&A allocation incorporates all usage below the peak; i.e., average demand. (Exhibit AB-28 at 23.) Staff also claimed that redundantly allocating costs based on average demand twice should not be considered a "serious flaw," because "[o]nly a portion of the peak day could be considered double counted" and the "average could be determined using the 364 days other than the peak day" such that "the average gas on the peak day would not be double counted." (See Krause 4 Tr 2574-75.) This is both an inaccurate characterization of the double counting problem and does not reflect the way

Consumers' system is designed, or the way it incurs costs. The A&E method does not remove the peak day from the average element of the process, instead it removes the peak day from the excess element of allocation. Considered in the context of the figure below, Staff's alternative calculations would remove only a tiny sliver of the gray section. The A&E method, however, is based upon removing the entirety of the gray portion when determining the excess demand element of the calculation, as that portion is already incorporated into the average demand element. (York 4 Tr 2094-97.)

Peak and Average Method



Peak and Average =

(LF x Factor 1) + (1 – LF) x Factor 2

Second, regarding an accurate allocation of costs, Staff's claim is also inconsistent with the way the system is designed and is not consistent with the way it provides "throughput" and "reliability" services for average and peak demand, respectively. (*Id.*) As Staff confirmed, the capacity used to serve average demand on 364 non-peak days is also available and used to serve

average demand on the 1 peak day of the year. (See Exhibit AB-28 at 22.) The capacity needed and used to serve average demand is not, however, sufficient to serve the daily demand above average; i.e., the Company installs capacity to serve peak demand in excess of that needed to serve average demand. (See *Id*. at 3 (Staff acknowledging that "assuming that 'excess or peaking capacity' refers to capacity greater than that that would be necessary to serve average demand, the need for such would be driven by any usage above average").) The extra capacity above the amount needed to serve average daily reflects the "reliability service," component of the system and is captured in the excess demand component of the A&E allocator. The A&E allocator therefore more accurately allocates costs associated with average and peak demand to the customer classes which contribute to those distinct demand and cause those costs. Again, as Staff acknowledged, "the A&E cost allocation method assigns greater costs to customers whose 'excess' NCP demand exceeds their average demand by more than another class proportionally." (*Id*.)

Indeed, while Staff asserted that "[h]igh and low load factor customers use the distribution system differently, so it is not fair to allocate the costs for using that system as if it were used for a single purpose, whether that be to meet design day peak demand, average throughput, or class/individual customer demands," the A&E method better reflects this reality. (Krause 4 Tr 2574-77.) As explained above, the A&E method is similar to the P&A method in that they both allocated costs based on customer classes' average demand weighted by the utility's system load factor. (York 4 Tr 2093-96.) The difference is that the A&E method does not redundantly incorporate average demand again into the peak demand element of its calculation. Thus, the A&E method reflects that "[b]ecause customer classes use the distribution system differently, it is reasonable to use an allocation method that combines how those disparate classes cause costs." (Krause 4 Tr 2574-77.) It also "balances the interests of high and low load factor customers" as

"an additional benefit of its use that stems directly from properly reflecting different uses of the system" better than the P&A method, as described above. (*Id.*) While Staff claimed "it is not fair to allocate the costs for using that system as if it were used for a single purpose," that is effectively what the P&A method does by redundantly over-allocating costs based on average demand twice, rather than properly accounting for which classes actually contribute to peak demand costs. In other words, unlike the A&E method, the P&A allocator does not reflect how the Company's system capacity is designed to provide the separate and distinct "throughput service" (i.e., that needed to serve average demand) and "reliability service" (i.e., that needed to serve peak demand) for the different customer classes which cause the associated costs. (York 4 Tr 2122-23.) Thus, both the A&E and P&A method satisfy the Commission's prior recognition that "there are sound reasons for allocating some portion of demand-related costs on the basis of non-peak throughput." (Krause 4 Tr 2574-77.) The A&E method, however, is more consistent with the Commission's discussion in its October 28, 1993 Order in Case No. U-1015. (*Id.*) While both methods reflect non-peak usage, or "throughput service," the A&E method more accurately allocates capacity costs incurred to provide the excess, or peak "reliability service" to the weather sensitive classes whose demand spikes on a peak day and thus cause the Company to incur those costs. (See Exhibit AB-28 at 1, 30.)

Again, the Company confirmed that it designs its system based on the peak (i.e., not average) demand of its customers, including the hour of maximum demand. (York 4 Tr 2089-93.) Thus, the Company builds its system to meet its peak day design requirement. (*Id.*; see Exhibit AB-2.) Those peaks are caused by weather sensitive classes with lower load factors. (See Exhibit AB-28 at 2-4. As Staff acknowledged, "[c]lasses with lower load factors [] will have greater excess demands relative to higher load factor classes regardless of the reason for the lower load factor."

(*Id*.) As Staff therefore further stated, the need for "capacity greater than that that would be necessary to serve average demand" is "driven by any usage above average" and the "A&E cost allocation method assigns greater costs to customers whose 'excess' NCP demand exceeds their average demand by more than another class proportionally." (*Id*.) Classes with lower load factors and greater excess demands therefore cause the need for peaking capacity. As those customer classes cause those costs they should be allocated as such. Staff confirmed that the A&E method "allocates a portion of costs based on average demand and a portion of costs on 'excess' demand, or that by which each class' non-coincident peak demand exceeds its average demand." (*Id*.) This reflects how lower load factor customers cause the utility to incur costs to meet their excess demand and properly allocates average and peak demand costs accordingly. By contrast, again, the P&A method redundantly incorporates average demand into the peak demand element of its allocation and spreads costs associated with excess demand to customer classes which do not cause them. Stated differently, the A&E method properly accounts for and distinguishes between customer classes' contributions to the Company's average demand, and their contribution to its peak demand. The P&A method blends the former into the latter and shifts peak demand costs to customers which do not contribute to that peak.

The Company's preferred CCOSS and Staff's objection to the Version 3 CCOSS therefore do not reflect cost causation. While Staff claimed that ABATE witness York did not support "why class NCP is appropriately considered a cost causative element other than it does not result in an allocation equivalent to coincident peak demand," as demonstrated above a noncoincident peak ("NCP") demand allocation is one of the named methods in the NARUC Gas Rate Design Manual cited by Staff. Further, using NCP demand instead of CP demand in this calculation ensures that the A&E allocator does not equal the CP allocator and incorporates average demand. (See Exhibit

AB-28 at 5.) Despite Staff's apparent misunderstanding, the demand component of the A&E allocator reflects the difference between NCP demand and average daily demand, which Staff itself acknowledged. (See Exhibit AB-28 at 2-4 (confirming "the "A&E cost allocation method assigns greater costs to customers whose 'excess' NCP demand exceeds their average demand by more than another class proportionally").) As explained above, and acknowledged by Staff, weather sensitive classes with lower load factors will have greater excess demands than higher load factor classes. (See Exhibit AB-28 at 2-4.) Thus, the A&E method assigns more capacity costs to weather sensitive classes who drive the need for excess capacity than the P&A allocator and is therefore more consistent with cost causation than the P&A approach. As such, despite Staff's claim, the A&E method better recognizes customer classes' distinct "usage of the system" and their contributions to the "system load factor, peak, and usage." (Revere 4 Tr 2761-64.)

Indeed, contrary to Staff's assertion, the A&E method *does* use system load factor to weight the average demand component consistent with the NARUC Manual, which explicitly utilizes the system load factor to weight the average demand component of the allocation. Further, while Staff asserted it is "uncertain what the justification for using system load factor for weighting is when the peak used to calculate that load factor is no longer part of the equation," it also acknowledged that the system load factor is used to determine the portion of capacity that would be needed if all customers used energy at a constant 100% load factor. (See Exhibit AB-28 at 6-8.) It represents the ratio of system average load to system peak load, and measures utilization. (*Id.*) In other words the A&E method properly distinguishes between customer classes' contributions to average demand and peak demand. Conflating the two for allocation purposes is the flaw in Staff's proposal.

Staff's claim that the P&A method better reflects the variability in load between classes is therefore wrong. (Revere 4 Tr 2761-64.) Instead, the P&A method skews an accurate representation of the variability between load classes and an accurate reflective cost allocation. (See Exhibit AB-1 at 11 ("The more granular approach of the A&E method avoids double counting the average demand volumes in the A&P methodology").) Again, Staff admitted that the A&E method's excess demand component assigns greater cost responsibility to gas deliveries that are more variable due to weather-sensitivity or other factors. (Exhibit AB-28 at 3, 15.) This is more reflective of cost-causation on the system, as the excess delivery capacity is necessary for and held in reserve to meet the demand of weather-sensitive loads that spike on a peak day. (See Exhibit AB-1 at 3-11.) Despite Staff's mischaracterizations the A&E method therefore aligns with the rationale that the system produces both peak day and off-peak service and assigns associated costs to customers proportionate to their respective contributions to those peak and average demands.

Customer load characteristics drive investment in the system, and are thus the basis for allocating costs in the COSS. While Staff appears to object to the concept that "customers should pay as if the system was built only to serve them and their load shape," the fundamental purpose of a CCOSS is that customer classes should indeed be allocated and pay the costs they cause, and which the utility incurs to serve them based on their load characteristics. (Revere 4 Tr 2761-64.) Staff's claim that "under such conditions, the system would likely not exist at all" is not an accurate reflection of how the proposed A&E allocation actually works and is contradicted by its own admissions regarding how different customer load characteristics drive the need for different capacity investments and different costs. (*Id*.) The A&E method simply reflects that average and excess (or peaking) capacity costs should be allocated to customer classes based on their proportionate responsibility for causing those costs. The A&E method does not "allocate the costs

for using the system as if it were used for a single purpose: to meet designed peak demand," it allocates them based on both average and peak demand in accordance with how they are caused by customers. (Krause 4 Tr 2576.) The A&E method thus best "combines how those disparate classes cause costs." (*Id*.)

Staff's further claim that the A&E method fails to recognize that delivering the average amount of gas on a peak day (or during a classes' NCP month) does not result in the same costs as on an average day is also inconsistent with its own statements and is incorrect. (Revere 4 Tr 2761-64.) Staff confirmed that "the system capacity used to serve average demand on 364 non-peak days is also available and used to serve average demand on the 1 peak day of the year." (Exhibit AB-28 at 22.) Further, Staff claimed that the difference between the average including and not including the peak day's contribution is "just over 1 percent." (Krause 4 Tr 2574-77.) Staff cannot claim there is a difference between average demand on peak and non-peak days which is simultaneously both material and nonmaterial for cost allocation purposes. Staff's claim also ignores the fixed nature of the Company's capacity costs. While Staff quibbled with the use of the term "fixed," gesturing towards the concept of depreciation, once delivery capacity is installed, the costs do not change depending on the amount of gas flowing through the system – whether that is a peak day or any other day. Excluding the concept of depreciation accounting, absent the addition of new customers or a change in system design day requirements, the cost of mains will not change regardless of changes in annual throughput that result from weather or conservation. (Exhibit AB-1 at 4-11; York 4 Tr 2089-93.) The Company's costs to serve both average and peak demand should be allocated to customer classes in accordance with how those customer classes contribute to those disparate demands and cause the utility to incur those costs.

Staff's objection to ABATE's proposed revenue apportionment approach is also inconsistent with its own recommendations. While Staff stated that an equitable revenue apportionment is "one that properly reflects the allocation of costs," for the reasons set out above its own strict adherence to the P&A method fails to do so. (Revere 4 Tr 2766.) Further, in DTE's last gas rate case the Staff's proposed rate design took the same approach ABATE has recommended here, as Staff explicitly recommended allocating costs in a way which deviated from the Company and its own proposed cost of service model. Specifically, Staff explained its approach as "using the 'alternate' COS to guide the spread of revenue responsibility amongst the transportation classes," which it also used in Case No. U-20940. (Case No. U-21291, Filing No. 344 (December 27, 2025), p 7.) In Case No. U-20940 Staff recommended the following:

> Staff has used the second alternate COSS, as modified for Staff's adjustments (hereafter referred to as Staff's Alternate COSS) as a guide to how revenue responsibility should be shifted between transportation schedules when adjustments must be made to maintain the current breakeven points. This better reflects the differences in cost between the current schedules and the mix of service levels on each, moving toward a more rational distribution of revenue responsibility. To effect this, I instructed Staff witness Madison S. Todd to keep each transportation schedule's share of the total transportation revenue requirement between the results of the COSS using the current methods of allocation and Staff's alternate COSS while conducting rate design. This is a reasonable interim solution, which is a step toward the current state of Consumers Gas' transportation rate design.. [(See Exhibit AB-28 at 18.)]

The Proposal for Decision in Case No. U-21291 similarly described Staff's approach as follows:

> Mr. Revere states that in DTE's previous case, the Commission agreed with Staff that what was then deemed Staff's second alternate COS should be used to shape the relative increases amongst transportation rate classes, and that a similar COS should be filed in its next rate case (the instant case). He adds that for the purposes of the instant case, Staff is not recommending the additional COSS be directly utilized, as it would be inappropriate to utilize the additional COSS directly, as recognizing the difference in costs in rates should be accompanied by a reexamination of the structure of rates. He states Staff has used the additional COSS, as modified for Staff's adjustments (Staff's Alternate COSS) as a guide to how revenue responsibility should be shifted between transportation schedules

> when adjustments must be made to maintain the current breakeven points. He states that he instructed Ms. [sic] Todd to keep each transportation schedule's share of the total transportation revenue requirement between the results of the COSS using the current methods of allocation and Staff's alternate COSS to the extent possible while conducting rate design. He asserts that this is a reasonable interim solution, which is a step toward the current state of Consumers Gas' transportation rate design. [(Case No. U-21291, Proposal for Decision (September 4, 2024), pp 343-44.)]

Staff's objection to ABATE's proposed use of the Version 2 and Version 3 CCOSS to guide and inform a reasonable rate design are therefore inconsistent with its own recommendations in DTE Gas Company's last two rate cases. It is also inconsistent with its own recommended revenue apportionment here, where Staff proposed a revenue apportionment which deviated from its CCOSS. (Exhibit AB-28 at 17.) Further, in terms of adhering to a CCOSS here and as discussed in greater detail below, Staff has recommended adjustments to maintain "breakeven points" between rate classes and explained that "[f]or the other transportation schedules, however, the delineations between them are effectively arbitrary (though they may initially have had some justification when put in place); the schedules are defined as they are due to the breakeven points, not due to any consideration of differential use of the system as they are for, say, electric distribution rates." (Revere 4 Tr 2764-67.) Staff's own proposed revenue apportionment therefore deviates from CCOSS results and instead reflects a number of Staff's own external adjustments. Staff's objection to ABATE's recommendation is therefore self-contradictory and meritless.

Furthermore, Staff's assertion that ABATE witness York's recommendation "arbitrarily determined whether the results of the A&P or A&E COS as more appropriate" is completely baseless and, given its lack of engagement with the actual record in this case, demonstrates how little weight Staff's recommendations on this issue should be granted. (Revere 4 Tr 2765.) As set out above, the A&E method both more accurately reflects how high and low-load factor customers cause the Company's costs for average and peak service and is more consistent with the

Commission's stated objectives for a cost allocation which reflects both average and peak usage. ABATE's proposed revenue apportionment considers the results of both the Version 2 and Version 3 CCOSS models to guide an equitable revenue apportionment consistent with Staff's own proposals in DTE's last two gas rate cases.

Specifically, ABATE's recommended revenue spread moved the Residential, GS-3, XLT, and XXLT classes halfway between the Version 2 and Version 3 CCOSS results. (See York 4 Tr 2119-24.) For GS-1, the results of both models were very close, and Staff's spread was just slightly higher than CCOSS. (*Id.*) ABATE's recommendation therefore included Staff's spread for mitigation purposes, as well as Staff's small increase for GS-2 despite all COSS models, even Staff's, showing a small decrease was necessary. (*Id.*) ABATE's recommended apportionment also resulted in a Rate ST increase of 1.55x system average and a slightly lower increase for Rate LT consistent with the CCOSS models demonstrating that Rate LT required a smaller increase to reach cost of service than Rate ST. As Staff's testimony in this and prior rate cases has demonstrated, revenue apportionment is commonly guided by CCOSS results and also requires judgment to recognize gradualism and avoid rate shock. Again, as explained above both Consumers and Staff similarly exercised judgment by using "rate stability" adjustments to deviate from their COSS results and arrive at a revenue spread and rate design. Indeed, Staff's own testimony explained that with regard to the current rate schedule delineations, which Staff proposed to maintain, it has "not been shown that the current rate schedule delineations are justified by differential use of the system." (Revere 4 Tr 2767.) ABATE's recommendation for apportioning revenue therefore takes the same approach (and, in some cases, the results) of Staff's own proposals and its objections should be rejected.

Developing cost of service rates requires determining how customer classes cause Consumers to incur its costs. The A&E method most accurately distinguishes between the capacity needed to serve average daily demand and peak demand and allocates the related costs to the customer classes in proportion to how they cause those respective capacity investments. Staff's objections to the Version 3 CCOSS are therefore entirely incorrect. Despite this misplaced opposition, however, ABATE does not recommend the Commission adopt the Version 3 CCOSS, but instead merely use it to guide a more equitable and cost of service-based cost allocation than the Company's preferred CCOSS and Staff's proposal. Doing so is consistent with past Commission precedent and Staff's own recommendations. The Commission should therefore adopt ABATE's proposed revenue apportionment in this proceeding.

F. Cost Allocation and Rate Design – Staff's proposed revenue apportionment allocates costs to transportation customers in excess of that indicated by a reasonable CCOSS.

As discussed above, and similar to Consumers' approach, while Staff's proposed CCOSS allocates costs to transportation customers in excess of the system average increase, its proposed revenue apportionment would assign even more costs to the transportation customers than suggested by its CCOSS. (See Exhibit S-6.) As this approach does not reflect cost of service and is both unreasonable and inequitable it should be rejected.

Staff's CCOSS and proposed revenue apportionment are described below:

TABLE JAY-2-RT

Staff's CCOSS (Version 2) vs.
Proposed Revenue Apportionment ($000)

Line	Rate Schedule	Delivery Revenues at Current Rates[1] (1)	Staff's CCOSS Increase / (Decrease) to Reach Cost of Service[2] Amount (2)	Percent (3)	Index (4)	Staff Proposed Increase / (Decrease)[1] Amount (5)	Percent (6)	Index (7)
1	Residential[3]	$1,112,113	$151,521	13.6%	1.19	$145,982	13.1%	1.15
2	GS-1[3]	172,968	7,529	4.4%	0.38	8,897	5.1%	0.45
3	GS-2[3]	131,566	(1,424)	-1.1%	(0.09)	2,294	1.7%	0.15
4	GS-3[3]	28,958	1,118	3.9%	0.34	579	2.0%	0.17
5	ST	34,864	9,480	27.2%	2.37	10,081	28.9%	2.52
6	LT	27,199	5,466	20.1%	1.75	5,977	22.0%	1.92
7	XLT	30,204	4,042	13.4%	1.17	4,674	15.5%	1.35
8	XXLT	10,129	(383)	-3.8%	(0.33)	(1,135)	-11.2%	(0.98)
9	Total	$1,548,002	$177,350	11.5%	1.00	$177,350	11.5%	1.00

Sources and Notes:
[1] Exhibit No. S-6.0, Schedule F-2, page 2.
[2] Exhibit No. S-6, Schedule F-1.1.
[3] Proposed revenues include incremental late payment revenue totaling $356,000 from WP-NCR-2.

As this table shows, Staff has proposed to increase revenues for Rates ST, LT, and XLT above Staff's CCOSS results and has proposed a rate decrease for Rate XXLT that is roughly three times larger than indicated by Staff's CCOSS. This approach is flawed for a number of reasons.

First, Staff's proposed revenue apportionment for the transportation classes is loosely based on the results of the P&A CCOSS. (See York 4 Tr 2120-24.) As discussed above, a P&A cost allocation method is inconsistent with the way in the Company designs its system and incurs costs and does not accurately assign costs to the customers which cause them. As such the P&A CCOSS should not be the only measure of class cost of service used to inform revenue distribution and rate design. Second, in addition to using a CCOSS which improperly allocates an excessive amount of costs to large users by redundantly allocating average demand costs twice, Staff's

proposed revenue apportionment for the transportation classes further exacerbates this inappropriate allocation by proposing an even greater amount of costs be allocated to those customers. Again, as with Consumers' proposed revenue apportionment, this approach compounds an inappropriate cost allocation method and even further deviates from Consumers' actual cost of service for its various customer classes. Deviating from a flawed CCOSS by exacerbating the flaws in a way that results in such a dramatic and inequitable result should not be approved.

Despite the alarming results of Staff's approach to adjusting rates outside its flawed CCOSS in a way that compounds the inequity and unreasonableness of the allocations, it is notable that Staff did not adequately explain its rational for its proposal. Instead, in its direct testimony Staff simply stated that it found that the rate stability targets used by the Company did not produce what Staff considered to be reasonable rate increases across the customer classes. (Rademacher 4 Tr 2585.) Thus, Staff simply decreased the stability target for GS-1 and GS-3 and increased the stability target for GS-2. (*Id*.) In its testimony Staff did not explain how Staff determined that the Company's rate stability targets were unreasonable, or why Staff's recommendations are reasonable, particularly considering the significant deviations from its CCOSS and the varying large increases and decreases resulting therefrom.

As explained above, ABATE's proposed revenue apportionment instead utilizes both the Company's Version 2 and Version 3 CCOSSs to produce rates which reflect how customer classes cause the Company's costs to meet average demand, *and* the Company's need to design the system to meet peak demand. This is more consistent with the Commission's discussion of the need for rates to reflect both how customers use and the Company designs its system. Specifically, as noted above, the Commission has indicated that a capacity allocator should recognize that the Company's system capacity provides two separate and distinct services. First, a portion of total

capacity is used every day of the year to serve average daily demands (i.e., "throughput service"). (York 4 Tr 2120-24.) Second, the additional capacity that exists above the portion that provides throughput service provides a "reliability service;" that is, there exists an amount of extra system capacity that is not needed unless daily demand exceeds the average, up to the yearly peak day demand on the system. (*Id*.) The manner in which customer classes cause the utility to incur costs for the amount of extra capacity needed to provide "reliability service" is captured through the Excess Demand component of the Version 3 CCOSS A&E allocator and is calculated as the *difference* between each class's Non-Coincident Peak ("NCP") Demand and Average Demand. (*Id*.) As shown in Diagram 1 above, mathematically, the P&A allocator does not capture the *difference* between peak and average demand; instead simply and redundantly blending the latter into the former. The P&A allocator therefore does not recognize how capacity is designed to provide the separate and distinct "throughput service" and "reliability service" Thus, the P&A allocator does not recognize the distinction between the two services (average and peak) provided by the Company's system capacity or how customers use those services and cause the associated costs.

Staff (and the Company)'s approach therefore relies on a method which redundantly overallocates costs based on average demand (despite the Company's system investment being drive by the need to meet peak demand) and further deviates from that method to artificially allocate even greater costs to certain customer classes. (See York 4 Tr 2120-24.) This does not reflect cost of service and produces rates which are unreasonable and inequitable. The Commission should therefore reject the Company and Staff's proposed revenue apportionment and instead adopt a cost allocation which reflects how customers cause the Company to incur costs. Specifically, a reasonable and appropriate revenue apportionment based on Staff's claimed

revenue deficiency, and with the more granular allocation of Other Distribution Plant described further below, is shown below.

TABLE JAY-3-RT

Alternative Revenue Apportionment ($000)

Line	Rate Schedule	Delivery Revenues at Current Rates[1] (1)	Staff Proposed Increase / (Decrease)[1] Amount (2)	Staff Proposed Increase / (Decrease)[1] Percent (3)	ABATE Proposed Increase / (Decrease) Amount (4)	ABATE Proposed Increase / (Decrease) Percent (5)
1	Residential	$1,112,113	$145,982	13.1%	$151,337	13.6%
2	GS-1	172,968	8,897	5.1%	8,897	5.1%
3	GS-2	131,566	2,294	1.7%	2,294	1.7%
4	GS-3	28,958	579	2.0%	1,905	6.6%
5	ST	34,864	10,081	28.9%	6,191	17.8%
6	LT	27,199	5,977	22.0%	3,100	11.4%
7	XLT	30,204	4,674	15.5%	2,943	9.7%
8	XXLT	10,129	(1,135)	-11.2%	683	6.7%
9	Total	$1,548,002	$177,350	11.5%	$177,350	11.5%

Sources and Notes:

[1] Exhibit No. S-6.0, Schedule F-2, page 2.

This cost allocation will best reflect cost of service principles and result in reasonable rates. Again, it's worth noting that for the Residential class this recommended revenue distribution produces an increase which is only 0.5% higher than that proposed by Staff's flawed approach, which equates to about a $0.27 per Residential customer per month difference. (*Id.*) This revenue apportionment will therefore bring the Residential class rates gradually in line with a more accurate cost of service as measured by both the Version 2 and Version 3 CCOSS models while producing an increase for transportation customers which is still above the system average. (*Id.*)

For the reasons set forth above Consumers and Staff's cost allocation and revenue apportionment proposals are flawed and do not reflect cost of service. The Commission should

therefore adopt a revenue distribution guided by the results of both the Version 2 and Version 3 CCOSSs and set customer and distribution charges, along with breakeven points, consistent with the recommendations further below. This approach will result in equitable rates that reflect cost causation, gradualism, and the avoidance of rate shock.

G. Cost Allocation and Rate Design – The Company's transportation rate design includes unreasonable adjustments to maintain arbitrary "break-even" points.

As part of the flaws described above the Company's transportation rate design for Rates ST, LT, XLT, and XXLT includes principal customer charges for Rate ST and Rate XXLT tied to the Company's preferred CCOSS, although the remaining rate design reflects shifts in the revenue requirement between the transportation rate schedules in order to maintain existing economic breakeven points.[21] (See Smith 4 Tr 1786-91; York 4 Tr 2102-06, 2124-25; Exhibit AB-1 at 12.) Because this approach is unreasonable the Commission should reject the Company's proposal.

The Company's proposed principal customer charges for Rate ST and Rate XXLT are set based on the results of its preferred CCOSS (Version 2), while the principal customer charges for Rates LT and XLT are set to maintain the existing economic breakeven points. (*Id.*) This results in customer charges for Rates LT and XLT being less than the customer charge indicated by the Company's CCOSS by 5% and 7%, respectively. (*Id.*) In other words, the Company (and Staff's) proposal(s) results in rates which deviate from cost of service. Indeed, the Company explicitly stated that its proposed rate design does not "align precisely with the current class COSS" and implicitly acknowledged that ABATE's proposal would force Consumers' rate design to do so. (Smith 4 Tr 1808-10.)

[21] The Company defines the economic breakeven point as the point of volumetric usage where revenue collected from one rate would equal revenue collected on a different rate. (Smith 4 Tr 1793; York 4 Tr 2103.)

In objecting to ABATE's recommendation the Company claimed that maintaining breakeven points allows for greater precision in revenue prediction and, therefore, greater accuracy in setting rates and minimizing potential customer confusion. (Smith 4 Tr 1808-10.) Consumers further asserted that it wishes to prevent rate shifting, because customers frequently shifting from rate to rate on a large scale could create revenue volatility for the Company. The Company clarified that "frequent shifts from rate to rate" means a circumstance in which a customer switches rate schedules every time the Company receives a rate order. (Exhibit AB-1 at 12.) This approach to altering rate class revenue to maintain breakeven points is unreasonable and should be rejected.

The Company's rationale does not support its proposal to modify its transportation cost allocation in a manner inconsistent with cost causation. Consumers provided no evidence to show that "frequent" rate shifting and revenue volatility would occur if rates for all transportation rate schedules were based on the CCOSS rather than a desire to maintain economic breakeven points. (York 4 Tr 2101-06; Exhibit AB-24 at 1-2.) Indeed, minimal rate shifting has occurred over the last several years and the Company's tariff provides that after a transportation customer selects a rate under which it will take service, the customer shall not be permitted to change from that rate to another until at least 12 months have elapsed. (*Id.*; see Consumers' Tariff Sheet No. C-19.00, Section C4.2, Choice of Rates.) Further, the greatest level of transportation customer rate switching in recent years occurred in 2024 (despite no change in economic breakeven points) and involved 87 Rate LT customers. (York 4 Tr 2104-06; Exhibit AB-1 at 12.) Despite its expressed concern regarding revenue volatility, even this outlier circumstance did not negatively affect the Company, as it experienced an approximate $37 million revenue sufficiency in 2024. (York 4 Tr 2104-06; Exhibit AB-3.) There is therefore no evidence to suggest that rate switching has happened or would happen at such a large scale that it would be detrimental if rates were set based on cost of service,

instead of set to maintain economic breakeven points. Further, even with some rate switching in recent years, the Company has continued to experience a revenue sufficiency nearly every year, meaning even evidenced rate switching has had little to no impact on revenue. (*Id*.)

The Company's concerns regarding rate switching and revenue volatility are therefore unsupported and unreasonable. Furthermore, the Company's proposal is also inconsistent with its own expressed rate design objectives. While the Company proposed shifting revenue responsibility to promote rate stability and moderate rate impacts, its proposal would result in class average rate increases ranging from 26% to 34% (or up to 2 times the system average) for the ST, LT, and XLT classes. Proposing this level of increases can hardly be considered moderating rate impacts. (York 4 Tr 2104-06; Exhibit AB-1 at 12-14.)

Staff also objected to ABATE's recommendation, arguing that the method of rate design proposed by ABATE "fails to either lock the breakevens in place or move determinants appropriately." (Revere 4 Tr 2767.) As explained above, Staff's position and explanation provide a basis for revisiting Consumers' transportation rate design, not locking it into place. Again, Staff acknowledged that "[i]t has not been shown that the current rate schedule delineations are justified by differential use of the system." (*Id*.) Further, Consumers acknowledged that it is not aware of natural gas utilities outside of Michigan that design transportation rates to maintain economic breakeven points between rate schedules to prevent rate switching. (Exhibit AB-24 at 3.) Maintaining breakeven points should therefore not be held out as an objective in and of itself, particularly where it results in dramatic and inequitable deviations from CCOSS models and significant increases for certain customer classes.

The Company's proposal is therefore unreasonable and should be rejected. The Commission should instead set the principal customer charges for the transportation rate schedules

based on the Company's Version 3 CCOSS, the distribution charges should be set to recover the remaining portion of the class revenue requirements shown in Table JAY-4, and the breakeven points should be recalculated accordingly. (York 4 Tr 2102-06.) ABATE's recommended transportation rate design is shown in Exhibit AB-4 and reflects the Company's claimed revenue deficiency, meaning it would need to be modified based on the final revenue requirement approved by the Commission.

H. Cost Allocation and Rate Design – The Company's uncollectible expense should be allocated to the identifiable customer classes which cause the Company to incur that cost.[22]

The Citizens Utility Board ("CUB") and Staff recommended the Commission allocate the Company's uncollectible costs across rate classes as a general cost of doing business, rather than allocating them to the specific customer classes responsible for causing those costs. (Bunch 4 Tr 2382-83; Krause 4 Tr 2570.) As this approach to cost allocation does not reflect cost of service principles the Commission should adopt its prior practice of allocating these costs to the customer classes which cause them.

While the Commission has recently considered uncollectible amounts a cost of doing business, they are very clearly a cost caused by specific identifiable customer classes and should be allocated as such. (York 4 Tr 2113-16.) The Commission has previously made this determination, recognizing that a "principle of cost allocation is that costs that are directly attributable to a particular customer or class of customer should be directly assigned to that customer or class" and "[a]s recognized by the NARUC Manual . . . uncollectibles expense is an

[22] This issue is addressed at Geller 4 Tr 1241 (accepting Staff's alternative allocation proposal); Bunch 4 Tr 2382-84 (recommending uncollectible expenses be allocated according to revenue), Exhibit CUB-3; Revere 4 Tr York 4 Tr 2113-16 (objecting to Staff's proposal); Lyons 4 Tr 2262 (objecting to Staff's proposal).

example of a customer-related cost that may be directly assigned to the class that is responsible." *In the Matter, on the Commission's Own Motion,* order of the Public Service Commission, entered June 15, 2015 (Case No. U-17689), pp 26-27. The Commission further stated that "to treat uncollectibles expense as overhead and allocate these costs to customers without considering how different classes of customers are actually causing the costs" can "lead to inter-class subsidies." *Id*. Thus, "[i]t is appropriate and consistent with regulatory ratemaking principles to directly assign such costs to the class that caused the costs." *Id*.

The Commission reaffirmed this approach in 2017, agreeing with an ALJ finding that classifying and allocating these costs based upon an overall allocation scheme "would violate principles of cost causation," and stating that this "issue has been addressed in numerous recent orders where the Commission has considered and rejected the Staff's proposal to spread this cost to all customers rather than focusing on the class responsible for the bulk of the expense." *In the Matter of the Application of Consumers Energy Co*, order of the Public Service Commission, entered February 28, 2017 (Case No. U-17990), pp 131-32; see also the Commission's December 11, 2015 Order in Case No. U-17767, pp 113-14 (adopting the PFD's recommendation rejecting Staff's proposal that uncollectibles costs are better allocated using an overall allocation method rather than by historical write-offs, and noting the argument that the ALJ's decision was supported by cost of service principles and the NARUC Manual); December 9, 2016 Order in Case No. U-17999, p 57 (reiterating that for uncollectible costs "[i]t is appropriate and consistent with regulatory ratemaking principles to directly assign such costs to the class that caused the costs" and the "Commission favors consideration of 'how different classes of customers are actually causing the costs'"); January 31, 2017 Order in Case No. U-18014, pp 102-03 (rejecting Staff's proposal to allocate uncollectibles on a cost of service percentage basis, based on total rates, fuel,

and purchased power costs, and stating that "[a]lthough the Staff asserted that its proposed allocation differs from the method rejected by the Commission in previous cases, the Staff admits that the currently-approved allocation method and the Staff's preferred method are both acceptable according to the NARUC Manual").

The Commission also made this finding in its July 31, 2017 Order in Case No. U-18124, where it rejected the exact arguments Staff and CUB make here. There the Commission noted that Staff supported its proposal as follows:

> The Staff and the Attorney General contended that UAE should be allocated to all customers as a general cost of doing business, because whether or not a customer pays their bill has nothing to do with how many customers share the same rate class, and there is no reason to burden others in the same rate class disproportionately with respect to the utility's overall cost of doing business.
>
> . . .
>
> The Attorney General and Staff's proposal to allocate uncollectibles based on total cost of service, plus cost of gas is reasonable in regulatory theory, and is supported by the [National Association of Regulatory Utility Commissioners] NARUC manual. [*In the Matter of the Application of DTE Electric Co*, order of the Public Service Commission, entered July 31, 2017 (Case No. U-18124), pp 109-11.]

In response to these claims the Commission found that "[a]s the Commission has stated regarding UAE, 'It is appropriate and consistent with regulatory ratemaking principles to directly assign such costs to the class that caused the costs'" and the "Commission continues to believe so." *Id*.

As indicated in these Commission decisions, this cost of service-based approach to allocating uncollectibles costs to the customer classes which cause them follows from the description of these costs in the NARUC Electric Utility Cost Allocation Manual, which provides the following:

> Customer-related costs (Accounts 901-917) include the costs of billing and collection, providing service information, and advertising and promotion of utility services. By their nature, it is difficult to determine the "cause" of these costs by

> any particular function of the utility's operation or by particular classes of their customers. **An exception would be Account 904, Uncollectible Accounts. Many utilities monitor the uncollectible account levels by tariff schedule. Therefore, it may be appropriate to directly assign uncollectible accounts expense to specific customer classes**. [(York 4 Tr 2113-16; National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* at 102 (January 1992) (emphasis added).)]

Thus, after noting that the purpose of CCOSS models is to attribute costs to different categories of customers based on how those customers cause costs to be incurred, the NARUC Manual specifically discusses uncollectible expense in the chapter dedicated to the classification and allocation of customer-related costs. (*Id*.) These costs are identifiably caused by specific customer classes and should be allocated as such.

The evidence in this case makes this clear. The Company's analysis of net write-offs (included in Exhibit CUB-3) demonstrates these costs are exclusively caused by a specific customer class – primarily Residential. (York 4 Tr 2113-16.) The Company tracks this data by rate schedule and it is undeniable that the Residential customers have been responsible for nearly 90 percent of net write-offs each year from 2021 through 2023. (*Id*.) Indeed, CUB explicitly acknowledged that Residential uncollectible expense has increased 53.7% from 2021 to 2023. (Bunch 4 Tr 2366.) Contrarily, large transportation customers have been responsible for little to no net write-offs (or even net negative net write-offs) during that same three-year period. (Exhibit CUB-3.) There is no evidence to suggest that the Company's projected uncollectible expense will be driven by a different rate class in the future test year.

CUB and Staff's proposal would therefore allocate these costs to customers which have no role in causing them whatsoever. Specifically, the Rate XLT and XXLT classes would receive an allocation of uncollectible expense despite not having caused *any* of this expense. More specifically, Staff and CUB's proposals would shift roughly $2.1 million and $2.5 million of projected uncollectible expense, respectively, to Non-Residential customers. (York 4 Tr 2113-16.)

This includes shifting approximately $460,000 of uncollectible expense to the Transportation class in excess of the amount allocated by the Company. Contrarily, Consumers' method allocates uncollectible expense to the classes which cause the expense. As such, as demonstrated by the Commission decisions discussed above and the principle of setting cost of service rates based on cost causation fundamentals described in the NARUC Manual, CUB and Staff's proposals are unjust, unreasonable, inconsistent with cost causation, and should be rejected.

More generally, CUB and Staff's recommendation represents yet another proposal to deviate from cost of service principles and shift further costs onto the transportation classes. As indicated above, Consumers' preferred CCOSS redundantly weights average demand twice when allocating distribution costs such that larger customers are inherently assigned a higher level of those costs. This is despite the fact that peak demand is the driver of Consumers' expense. In other words, despite the Company's costs being clearly driven by the need to meet *peak* demand, the preferred CCOSS assigns a greater portion of costs on *average* demand. The Company (and Staff)'s proposed revenue apportionment goes even further, asking the Commission to assign even greater amounts of costs to transportation customers than suggested by its flawed CCOSS. In addition to these proposals not reflecting cost causation or cost of service principles, as indicated above, Staff and CUB's proposal here would shift *even more* costs to transportation customers despite those customers again demonstrably not causing those costs. It is neither reasonable nor prudent for the Commission to approve multiple cost allocation proposals which all fail to reflect the Company's actual cost of service and operate to shift millions upon millions of dollars in cost recovery exclusively to transportation customers. The Commission should therefore reject CUB and Staff's proposals and adopt the Company's recommendation.

I. Cost Allocation and Rate Design – The Commission should adopt the LBWL/MSU proposal to allocate Other Distribution Plant using a weighted average for high pressure and non-high pressure distribution mains.[23]

The LBWL/MSU recommended allocating Other Distribution Plant in Federal Energy Regulatory Commission ("FERC") Accounts 374, 375, 377, and 378 using Allocator 217 instead of Allocator 104 as proposed by the Company. (Lyons 4 Tr 2256.) Because this is a reasonable approach to first functionalize and then allocate distribution plant, recognizing the high pressure ("HP") and non-HP infrastructure used to provide service to the various classes, the Commission should approve this proposal as refined by Staff for Account 378. Staff recommended that the Commission approve a more granular approach than the Company's to the allocation of Measuring and Regulator Stations plant in Account 378, considering the different pressure levels that this equipment serves. (Revere 4 Tr 2755-56; Geller 4 Tr 1243.) Both of these proposals are reasonable and should be approved. (York 4 Tr 2117-19.)

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.

[23] This issue is addressed at Lyons 4 Tr 2255-57 (proposing an alternative allocation of certain accounts); Geller 4 Tr 1231-33; 1237, 1243-45 (objecting to LBWL-MSU's proposal); York 4 Tr 2117-19 (recommending the Commission adopt the proposal); Revere 4 Tr 2760-61 (objecting to portions of LBWL-MSU's proposal).

Respectfully submitted,

CLARK HILL PLC

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Date: June 25, 2025

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	Case No. U-21806
for authority to increase its rates for the	)	
distribution of natural gas and for other relief.	)	ALJ James M. Varchetti
	)	

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF WAYNE)

Stephen A. Campbell, being first duly sworn, deposes and says that on June 25, 2025, he did cause to be served the ***Association of Businesses Advocating Tariff Equity's 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.

Stephen A. Campbell

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SERVICE LIST
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