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BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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| In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief. | ) ) ) ) ) | Case No. U-20697 |

At the December 17, 2020 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Sally A. Talberg, Commissioner
Hon. Tremaine L. Phillips, Commissioner

**ORDER**

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## I. HISTORY OF PROCEEDINGS

On February 27, 2020, Consumers Energy Company (Consumers) filed an application requesting authority to increase its retail rates for the generation and distribution of electricity by $244 million. Consumers also requested other forms of regulatory relief including miscellaneous accounting authority. The company is currently providing service pursuant to rates established by the January 9, 2019 order in Case No. U-20134 approving a settlement agreement (January 9 order).

According to Consumers, the rate increase sought in this proceeding is based on the company's projections for relevant items of investment, expense, and revenue for a test year covering the 12-month period from January 1, 2021, through December 31, 2021, based on the 2018 historical year. In its application, the company stated that the rate increase is necessary to recover ongoing investments in generation and distribution assets, ongoing investments related to environmental and legal compliance, ongoing investments in enhanced technology, increased operations and maintenance (O&M) expenditures, and increased financing costs. Application, pp. 2-3. The company also seeks tariff changes. Consumers proposed a return on equity (ROE) of 10.50%, with an overall rate of return of 6.09%. Consumers' projected rate base for the test year in its initial filing was approximately $11.8 billion.

On March 23, 2020, Administrative Law Judge Sally L. Wallace (ALJ) conducted a prehearing conference.[1] The ALJ granted petitions to intervene filed by The Kroger Co. (Kroger); Michigan Department of Attorney General (Attorney General); the Association of Businesses Advocating Tariff Equity (ABATE); Michigan Environmental Council (MEC), Natural Resources Defense Council, Sierra Club, and Citizens Utility Board (collectively, the MEC Coalition); Residential Customer Group (RCG); City of Grand Rapids (Grand Rapids); Michigan Cable Telecommunications Association; Hemlock Semiconductor Operations LLC (HSC); Midland Cogeneration Ventures, LP; Michigan Energy Innovations Business Council and Institute for Energy Innovation (together, EIBC/IEI); Environmental Law and Policy Center, Ecology Center, Solar Energy Industries Association, Great Lakes Renewable Energy Association, and Vote Solar (collectively, the Joint Clean Energy Organizations or JCEO); Utility Workers Council, Utility Workers Union of America, AFL-CIO; Energy Michigan; ChargePoint, Inc. (ChargePoint); Michigan Municipal Association of Utility Issues (MAUI); and Wal-Mart Stores East, LP and Sam's East, Inc. (Walmart). The Commission Staff (Staff) also participated, and the Michigan Air Conditioning Contractors Association presented comments pursuant to Mich Admin Code, R 792.10413. A schedule for the proceeding was established by the ALJ in accordance with the 10-month rate case deadline required by MCL 460.6a(5).

On March 24, 2020, the ALJ adopted a protective order.

On March 31, 2020, the ALJ denied a petition to intervene filed by Mr. Phil Forner. The Commission affirmed the denial in orders issued on May 19 and July 23, 2020.

[1] Due to the novel coronavirus (COVID-19) pandemic, and consistent with Executive Orders and Executive Directives, all hearings were held via telephone and video conferencing using the Microsoft Teams platform.

Direct testimony was filed by the intervenors on June 24, 2020, and rebuttal testimony was filed on July 14, 2020. On July 27, 2020, the ALJ granted in part and denied in part a motion to strike certain rebuttal evidence.

Evidentiary hearings were held on July 29-31 and August 3-5, 2020, where 15 witnesses appeared for cross-examination and the testimony of the remaining witnesses was bound into the record without appearing. Timely initial and reply briefs were filed.

The ALJ issued a Proposal for Decision (PFD) on October 22, 2020. On November 10, 2020, Consumers, the Staff, the Attorney General, ABATE, the MEC Coalition, JCEO, EIBC/IEI, Grand Rapids, ChargePoint, MAUI, and RCG filed exceptions. Replies to exceptions were filed by Consumers, the Staff, the Attorney General, the MEC Coalition, MAUI, Grand Rapids, ChargePoint, Energy Michigan, EIBC/IEI, ABATE, JCEO, and RCG on November 20, 2020.

The record consists of 4,923 pages of transcript and over 500 exhibits received into evidence.

## II. TEST YEAR

In developing its rates for this proceeding, Consumers relied on a projected test year from January 1, 2021, through December 31, 2021, explaining that, in determining test year amounts, it began with the 2018 historical year adjusted for known and measurable changes. 6 Tr 2210. No party proposed an alternative test year; however, RCG argued that the commencement of the test year should coincide with the date of the application.

The ALJ recommended adoption of the proposed test year. PFD, p. 37. She found that, based on her review of recent Commission orders rejecting the same argument, RCG's proposal should be rejected. *Id.* The ALJ noted that "concerns regarding the reliability of the company's projections are considered in the context of specific challenges to the company's presentations." PFD, p. 38.

In exceptions and replies to exceptions, the parties make the same arguments that were made before the ALJ and in prior cases.

The Commission again rejects RCG's contention that the test year may be prescribed. *See,* May 2, 2019 order in Case No. U-20162 (May 2 order), p. 4; May 8, 2020 order in Case No. U-20561 (May 8 order), pp. 11-12. MCL 460.6a(1) provides that "[a] utility may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges." The test year may be in the future, and the 12 months must be consecutive; those are the requirements of the statute. The burden is on the utility to prove the accuracy of each and every test year projection. The Commission approves the proposed test year of January 1, 2021 through December 31, 2021.[2]

## III. RATE BASE

A utility's rate base consists of the capital invested in used and useful utility plant, plus the utility's working capital requirements, less accumulated depreciation. In initial briefs, Consumers projected a total electric rate base of $11,891,065,000, and the Staff calculated a total rate base of $11,755,200,000. Consumers stated that its five-year Electric Distribution Infrastructure Investment Plan (EDIIP) (filed as Exhibit A-111 in Case No. U-20134) and its integrated resources plan (IRP) (approved in the June 7, 2019 order in Case No. U-20165 (June 7 order) reflect the company's plan to invest approximately $600 million in distribution capital each year through 2022.

[2] Because the test year is also the calendar year, "test year" and "2021" are used interchangeably throughout this order. The years 2019 and 2020 are sometimes referred to as "bridge" years, because they are the bridge between the historical 2018 year and the test year.

The ALJ began her analysis of rate base by noting that an adjustment to a cost projection does not constitute a permanent disallowance, but rather only reflects the fact that the specified cost has not been "sufficiently supported <u>at this time</u>." PFD, p. 39 (emphasis in original). She emphasizes that reasonable and prudent costs will be incorporated into rate base in future rate cases, and costs may also be deferred.

A. Net Utility Plant

Net plant consists of plant in service, plant held for future use, and construction work in progress (CWIP), less the depreciation reserve, which includes accumulated depreciation, amortization, and depletion. Consumers' projected capital expenditures are broken down into the following categories: distribution, generation, information technology (IT), business services, corporate, customer experience, and demand response (DR). Exhibit A-12, Schedule B-5.

1. Contingency

Consumers included $7.467 million in contingency expenditures for generation capital expense in 2020, and $10.462 million in 2021. Exhibit A-12, Schedule B-5.2. The Staff identified an additional $4.588 million in contingency for operational support capital expenditures, for a total of approximately $22.5 million. Exhibit S-26.1; 8 Tr 4880.

The Staff and the Attorney General objected to the inclusion of contingency costs on grounds that they are speculative and they noted extensive Commission precedent disallowing these costs.

On rebuttal, Consumers reduced its projected contingency to zero for 2020, and further argued that it will exceed its 2020 projected capital expense by over $5 million. Citing another recent rate case, the Staff argued that the Commission should reject this late attempt to convert contingency costs into actual costs. *See,* September 26, 2019 order in Case No. U-20322 (September 26 order), p. 41.

The ALJ recommended that the total projected contingency expense be disallowed. She took note of the Commission's consistent rejection of these costs, and further found that "the Commission has not accepted expense updates that first appear in rebuttal when other parties do not have sufficient time to assess the reasonableness and prudence of these additional costs." PFD, p. 41.

In exceptions and replies to exceptions, the parties repeat the arguments they made before the ALJ and in many prior cases.

The Commission agrees with the ALJ that Consumers' total projected contingency costs of approximately $22.5 million (which includes those costs now alleged to be actual costs) should be disallowed. As the Commission has repeatedly found, although allowing for contingency may be appropriate in project planning, the inclusion of these costs in customer rates is unjust and unreasonable. *See*, November 19, 2015 order in Case No. U-17735 (November 19 order), pp. 7-11; December 11, 2015 order in Case No. U-17767, pp. 19-20; December 9, 2016 order in Case No. U-17999, pp. 4-6; January 31, 2017 order in Case No. U-18014 (January 31 order), pp. 12-13; March 29, 2018 order in Case No. U-18322 (March 29 order), p. 11; April 12, 2018 order in Case No. U-18370, p. 5; May 2 order, p. 6; and September 26 order, p. 41. The Commission further agrees with the ALJ and the Staff that the attempt to transform contingency costs to actual costs in rebuttal does not provide sufficient time for other parties to "assess the reasonableness and prudence of these additional costs." PFD, p. 41.

2. Distribution Capital Expenditures

Consumers projected total distribution capital expenditures of $628,865 for 2019, $552,142,000 for 2020, and $722,675,000 for the 2021 test year. The Staff, the Attorney General, the MEC Coalition, and JCEO presented objections that are addressed by program and subprogram. The heading for each subprogram, below, contains the lines on which it can be found in Exhibit A-29.

a. New Business (Lines 1-6, 7)

For this cost category, Consumers projected expenditures totaling $131.8 million for 2019, $131.7 million for 2020, and $145.2 million for the test year.

The MEC Coalition argued that total test year spending in the New Business program should be limited to the 2014 actual spending amount of $62.7 million, and that, if spending is higher or lower than this amount, the proposal to implement regulatory asset/liability treatment for over- or underspending on New Business programs will protect the company.[3] The MEC Coalition argued that COVID-19 will have a recessionary effect on Michigan's economy, and picked the 2014 actual amount as being analogous to 2021, in the sense that 2014 was a few years after the Great Recession caused by the mortgage crisis and represents a proxy for 2021 economic conditions. 8 Tr 3663-3664.

The ALJ recommended adoption of the MEC Coalition's proposal to limit test year spending in this category to $62.7 million, finding that new customer commitments are uncertain and that 2021 is likely to be similar to 2014 in terms of market conditions. PFD, p. 43. She also noted that the continuation of deferred accounting will adequately protect both the utility and ratepayers if spending is higher or lower than what is approved. Alternatively, the ALJ suggested that the five-year average of $85.078 million or the 2020 projection could be adopted as the test year amount for this cost category. While recommending the MEC Coalition's proposed overall disallowance, the ALJ indicated that, "recognizing that the Commission may find that an

[3] The MEC Coalition made similar overall test year reduction proposals for the Demand Failures and Reliability cost categories, which are discussed below.

alternative proposal is a more reasonable approach to addressing projected New Business spending, this PFD also analyzes the specific adjustments proposed by Staff and the Attorney General to the Lines Strategic Customers-HVD [high voltage distribution] sub-program." PFD, p. 44.

In exceptions, Consumers asks the Commission to reject the "extreme cuts to the Company's projected 2021 spending in the New Business, Demand Failures, and Reliability programs, in the amount of approximately $198.4 million" proposed by the MEC Coalition, on grounds that they lack evidentiary support and are based on speculation. Consumers' exceptions, p. 3. Consumers contends that the MEC Coalition's proposal is admittedly not based on its review of the evidence on the record, but is instead based on policy considerations. 8 Tr 3651-3652. Consumers objects to the MEC Coalition's testimony regarding its goal of achieving the lowest possible rates while maintaining adequate service quality, and the MEC Coalition's assertion that it is not "practical for the Commission, in this proceeding, to individually evaluate the reasonableness and prudence of every distribution project contemplated by the Company." 8 Tr 3651, 3643.

Consumers contends that the MEC Coalition failed to provide evidence regarding the state of the Michigan economy in 2021 when the new rates will be implemented, and failed to show that distribution reliability would not suffer if these deep cuts are made. 6 Tr 1339-1340; 8 Tr 3647. Consumers asserts that "even the investment levels proposed by the Company for the 2021 test year in this rate case do not reach the point of keeping up with deterioration, as human and material resource constraints prevent a larger ramp-up of work." Consumers' exceptions, pp. 5-6; 6 Tr 1340. Consumers further asserts that its average investment levels in the 2014 through 2018 period contributed to worsening deterioration and therefore a return to those levels is a mistake. Consumers maintains that it has presented substantial evidence showing a need for these investments, and the MEC Coalition presented no evidence showing what the impact on overall system reliability would be if the cuts are adopted. Consumers contends that the Commission's decision must be based on evidence. MCL 460.6a(1).

Regarding New Business specifically, Consumers argues that it provided evidence that the projects in this category are not uncertain, and that investment in this category has not been dramatically affected by the pandemic. 6 Tr 1354. While program activity decreased in April 2020, Consumers testified that it has rebounded since then, and the company will be spending slightly more than what it projected. 6 Tr 1355. Consumers argues that the MEC Coalition failed to present evidence that program activity will actually be depressed in 2021. Consumers also calls the use of 2014 as a proxy for 2021 arbitrary, arguing that 2014 was not actually closely tied to the Great Recession. 6 Tr 1356. Finally, Consumers posits that deferred accounting treatment cannot rationalize an extreme spending cut, particularly where the record reflects that the company will be overspending in the disputed cost category.

In reply to Consumers, the MEC Coalition argues that distribution system investment is the primary driver for this rate increase request, and that distribution spending increases affect residential customers more than other customer classes. The MEC Coalition notes that "[r]eliability spending is discretionary, non-emergency, long-term-oriented spending." MEC Coalition's replies to exceptions, p. 4. The MEC Coalition urges the Commission to focus on affordability, "particularly in light of the COVID-induced economic hardships many Michiganders are currently facing." *Id.* The MEC Coalition posits that Consumers is not responding appropriately to the current recession and the consequent economic concerns. The MEC Coalition argues that it is impractical for the Commission to individually evaluate the reasonableness, prudence, and efficiency of each of the over 1,500 individual projects subsumed under Consumers' $722 million total spending request. 8 Tr 3651.

The MEC Coalition contends that its recommendations are based on both policy and record evidence, and objects to the characterization of its proposals as extreme, arguing that its proposals are proportional to the spending request increases projected by Consumers. The MEC Coalition contends that the Commission's decision must balance reliability against the impact of the increase on the customer, and notes that the Commission may reject even unrebutted evidence. The MEC Coalition argues that, in any case, Consumers' provided no record evidence showing that the proposed spending reductions would have an adverse impact on system reliability, but that, "[t]he Commission must weigh and balance competing policy interests of customer impacts and reliability, even if reliability may suffer as a result. Reliability should not overshadow customer impact; the Commission must balance both." *Id.*, p. 19 (footnote omitted). Finally, the MEC Coalition contends that its concerns about the economy are not speculative, stating:

> [I]t may be unknowable whether this unprecedented worldwide pandemic will be fast and furious and then pre-recession economic conditions will resume; or whether instead there will be longer impacts, and where, and to whom. What is known is that these economic conditions continue to exist, Consumers has the burden to support the reasonableness of its projections, and the Company made no effort to even consider those conditions in making its requests at any point during the pendency of this rate case. The most reasonable, prudent, and responsible approach to address the Company's requested rate increase is to support the tree trimming surge and reduce substantial discretionary spending increases for Reliability in particular, while providing more moderate increases with some two-way deferred accounting for distribution spending where costs are beyond direct utility control (i.e., Demand Failure, Rehabilitation), as Mr. Ozar recommended.

*Id.,* p. 23 (footnote omitted). The MEC Coalition notes that it also advocated tailored spending cuts within subprograms, in addition to the larger cuts discussed in this section.

Regarding New Business specifically, the MEC Coalition contends that new business is market driven, and that Consumers' projections were formulated before the current recession. The MEC Coalition warns that the predicted new business may not materialize because of the pandemic/recession, and supports regulatory asset and liability treatment for over/under spending in this category as protection for the company and ratepayers. 8 Tr 3663-3664. The MEC Coalition acknowledges that Consumers provided data on rebuttal showing that low voltage distribution (LVD) lines spending dropped from March to May 2020, and increased from May to June 2020, but argues that this data provides little insight into the state of the economy for 2021.

The Commission is not persuaded that it should adopt the proposed overall reduction to the New Business program. The Commission is not convinced that 2014 presents a strong analogy to 2021. The Great Recession began six years before 2014 and arose from wholly different circumstances than the current economic crisis, which is still ongoing and thus is not ripe for "post-recessionary" treatment. Moreover, the MEC Coalition's arguments regarding the need to balance affordability against service quality ignore the Commission's obligation to set rates based on the cost of providing service to each customer class. MCL 460.11(1). The Commission rejects the MEC Coalition's proposed reduction based on the 2014 spend, but addresses the line item reductions below. Regulatory accounting treatment is also addressed below.

i. Lines Strategic Customers – High Voltage Distribution (Line 3)

Turning to this line item under New Business, Consumers forecasted capital expenditures of $12,114,000 for 2020 and $17,281,000 for 2021 to build new HVD lines for large strategic customers.

The Staff and the Attorney General recommended reductions to this subprogram on grounds that many of these projects had not been identified and were therefore placeholders. The Staff testified that the company's application included \$3.0 million in spending in 2020[4] for projects that were simply not identified, and argued that this amount should be halved, noting that Consumers spent only 40% of the allowed amount for this category in 2019. 8 Tr 4895. The Attorney General argued that the total 2020 amount associated with unidentified projects should be disallowed because it represents placeholder spending for projects that may never materialize. Consumers countered that its projections are based on reasonable expectations.

The ALJ recommended adoption of the Attorney General's proposed \$3 million disallowance for this subprogram for 2020, finding that "the Commission has consistently determined that 'placeholder' amounts for unidentified projects should not be recovered in current rates due to the uncertainty about both the cost and whether the project will actually be constructed." PFD, pp. 45-46; *see also*, p. 54. The ALJ also found Consumers' expectations about the emergence of these projects to be speculative.

In exceptions, Consumers contends that "[i]f there is spending in a specific program for a to be determined [sic] project, it is not based on an unsupported guess and is instead based on reasonable expectations, given historical spending levels and observed trends, that additional projects will emerge." Consumers' exceptions, pp. 12-13; 6 Tr 1321. Consumers emphasizes that projects have different timelines, complexity levels, inspection cycles and lead times; and projects may be known years, months, or weeks in advance, but some can only be identified on a "rolling basis." 6 Tr 1321-1322. Consumers contends that calling something a "placeholder" is false because it assumes that "the Company could have identified all projects in the above discussed subprograms prior to the filing of this proceeding in late February 2020," which is not possible.

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[4] Both the Staff and the Attorney General originally objected to the test year amounts as well, but later withdrew that objection. PFD, p. 45.

Consumers' exceptions, p. 13. Consumers argues that it is neither possible nor prudent to "pre-identify all possible projects" prior to the filing of a rate case and that its initially provided projections are appropriate for setting reasonable and prudent rates. *Id.*

Consumers contends that the point of updating its cost information during the discovery and rebuttal stages of the case is "to establish how the Company's rolling project identification approach works and also establish that this approach will result in the Company spending what it initially projected to spend." *Id.,* p. 14. Consumers contends that this issue of "placeholders" punishes the utility for providing more project level detail and greater transparency, noting that it only began to provide subprogram information in Case No. U-20134 and in the instant case. Consumers states that if every investment dollar must be tied to a specific project, this "threatens to force the Company's evidentiary presentation backwards, not forward." *Id.*, p. 15. Consumers asks that, if the Commission approves cost reductions that are based on alleged "placeholders," then the Commission "should also approve the deferred accounting treatment, as proposed by the Company, in the affected subprograms, subject to the same stipulations offered by Staff." *Id.*, p. 15, n. 2; 6 Tr 1322.

Finally, turning back to the disputed line item, Consumers notes that on rebuttal it provided identification of two additional projects for the test year in this cost category and confirmed that it continues to receive emergent customer requests. 6 Tr 1323. Citing the example of a customer who contacted the company in July 2020 regarding expedited relocation of several spans of 46 kilovolt (kV) line to accommodate a factory expansion, Consumers posits the importance of approving some unidentified spending in the bridge year, recognizing the fact that the company's projections are based on experience.

In reply to Consumers, the Attorney General reminds Consumers that it carries the burden of proof to support its revenue request and to show that its projections are reasonable and prudent, and contends that Consumers' "argument that it is not possible or prudent to pre-identify all possible projects is completely opposite to the standards for ratemaking." Attorney General's replies to exceptions, p. 12; *see also*, pp. 6-8. The Attorney General also argues that "the fact that [Consumers] was less transparent in the past does not excuse its failure to support its expenditures in this case." *Id.*, p. 13. The Attorney General notes that projections included in rate base earn a return of and on the amount and recover depreciation expense as well. She argues that placeholders should not be included.

In reply to Consumers, the Staff asserts that, for planned projects, there should be no placeholders.

> Staff's position is that projects with short lead times or those identified on a rolling basis should not be included in the Company's request for recovery unless relevant details about the projects can be provided. If the Company wants cost recovery for a project in a planned program, then it should know about the project many months in advance and provide the relevant details. These details include: the applicable sub-program; project description, line, substation or location; spending amount; number of units; unit type; and investment category. If the Company cannot provide this information, then it should exhibit restraint and ask for recovery in a future rate case once the projects and their relevant details are known.

Staff's replies to exceptions, p. 12. The Staff contends that there is not enough time to review placeholder project amounts that are fleshed out on rebuttal.

The issue of placeholders is one which the Commission has addressed in previous rate cases. Citing precedent from 2009, 2010, 2012, and 2016, the Commission offered this guidance in 2017:

> The Commission agrees with the ALJ that including "placeholder" amounts in the company's initial filing, and then attempting to justify these amounts later is unreasonable. The Commission has repeatedly cautioned DTE Electric [Company] and other utilities:

> As the Commission discussed in its November 2, 2009 order in Case No. U-15645, p. 8, Section 6a(1) of Act 286, MCL 460.6a(1), provides that a utility "may use projected costs and revenues for a future consecutive 12-month period" to develop its requested rates and charges. The Commission added that the Staff and intervenors should direct their focus "upon the strengths and weaknesses of the evidentiary presentations of the parties regarding specific expense and revenue projections." In a case where a utility decides to base its filing on a fully projected test year, the utility bears the burden to substantiate its projections. Given the time constraints under Act 286, all evidence (or sources of evidence) in support of the company's projections should be included in the company's initial filing. If the Staff or intervenors find insufficient support for some of the utility's projections they may endeavor to validate the company's projection through discovery and audit requests. If the utility cannot or will not provide sufficient support for a particular revenue or expense item (particularly for an item that substantially deviates from the historical data) the Staff, intervenors, or the Commission may choose an alternative method for determining the projection.

January 11, 2010 order in Case No. U-15768, pp. 9-10. *See also*, September 8, 2016 order in Case No. U-17895, p. 4.

In addition, the Commission has frequently discussed the proper use of rebuttal. For example, in the March 8, 2012 order in Case No. U-16034-R, pp. 9-10, the Commission determined:

> Evidence which could have been offered in a party's main case may be rejected if offered as rebuttal evidence, and this decision is within the discretion of the referee. October 30, 1984 order in Case No. U-7660, p. 3. It is true that the Commission may exercise broad latitude in considering evidence that might be rejected in a courtroom. However, that does not mean that, in cases whose outcome will affect customers' bills, the parties may divide their proofs in such a way as to prevent the opposition from being able to adequately review and respond to important evidence. The rule against improper rebuttal "is generally aimed at preventing the unfair ordering of proofs." [*People v*] *Vasher*, 449 Mich [494] at 505. . . .

In this instance, the company failed to adequately support its spending on this item in its initial filing, and appears to have used rebuttal to bolster its request once it had determined how it planned to spend these amounts.

January 31 order, pp. 30-32 (footnote omitted); *see, e.g.*, May 8 order, pp. 47-48, 58-63, 72.

Regarding the appropriate use of rebuttal in a rate case, the Commission has stated:

> As with other issues in rate base and cost of service, it is not adequate to present the primary evidence in support of the direct case on rebuttal when the parties can no longer test the evidence (other than through cross-examination). Proper rebuttal evidence is "that given by one party to contradict, repel, explain or disprove evidence produced by the other party and tending directly to weaken or impeach the same." *Kirk v Ford Motor Co*, 147 Mich App 337, 345; 383 NW2d 193 (1985) (citation omitted); June 3, 2010 order in Case No. U-15985, pp. 23-24. Rebuttal is not intended for presentation of the entire direct case in support of a capital expense category.

September 26 order, p. 39.

Consumers contends that it needs to be able to present its case on a "rolling" basis – that it is not intentionally dividing its proofs, but rather is simply not able to present a complete case with its application because it does not yet have complete information regarding projected costs. The Commission acknowledges that the company is not presenting a complete case, but disagrees that discovery and cross-examination offer sufficient procedural safeguards such that Consumers should be allowed to present a significant portion of its case for the first time on rebuttal or in discovery. Consumers (and other utilities) sought and received from the Legislature the right to a fully projected test year, and the right to file a rate case every 12 months and receive a final order in that case within 10 months of the filing. MCL 460.6a(5), (6). These short timelines mean that the utility need not wait unduly for the opportunity to raise rates when revenues become deficient, but they do not mean that an immature case may be filed in which the necessary evidence is actually developed during the 10 months. Rebuttal evidence is clearly relevant evidence, and there are rate base decisions herein that rely on rebuttal. But rebuttal may not be used as a substitute for the direct case that must support the application, and to which intervenors are expected to respond.

Whether the problem is labeled as placeholders, or costs prematurely included in rate base, or projections supported by estimates with a low degree of reliability (as is discussed more below with respect to generation capital expenditures), the Commission finds that the direct evidence offered in support of a utility's application for a rate increase must meet a minimum standard of detail and credibility. As the Staff phrased it, a minimal level of required detail would include: "the applicable sub-program; project description, line, substation or location; spending amount; number of units; unit type; and investment category." Staff's replies to exceptions, p. 12. Of course, detail as to the timing must also be included. The Commission observes that *all* project descriptions for capital expenditures of any type need to comply with the Rate Case Filing Requirements for Capital Expenditures (Electric). July 31, 2017 order in Case No. U-18238, filing # U-18238-0037, Rate Case Filing Requirements, Attachment 9, pp. 2-3.[5] Rather than reprint them here, the Commission recommends that Consumers review these filing requirements, which were adopted by Commission order. If the required information cannot be provided in the direct evidence supporting the initial filing, but could potentially be provided later in rebuttal evidence, then the project is one that should be included in the utility's next rate case, as soon as 12 months later, where the utility can supply the requisite information. The Commission recognizes that some categories of expenditure will only emerge during the test year. But Consumers' request to address dozens of expense categories as emergent expenses and to provide its evidence on a rolling basis throughout the ten-month process does not comport with the setting of just and reasonable rates. MCL 460.6; MCL 460.6a.

For these reasons, and for the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ and approves the Attorney General's proposed $3 million reduction to 2020 capital expenditures. As requested by Consumers, and based on the Staff's view that these categories involve emergent spending, the Commission approves deferred

[5] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001UW8pAAG

accounting treatment for New Business, Asset Relocations, and Demand Failures, with the conditions stipulated by the Staff. 6 Tr 1322, 1866; 8 Tr 4881-4884. As the Staff notes, Consumers was granted deferred accounting treatment for these three cost categories as a result of the settlement agreement approved in the January 9 order, and the Staff recommends that the Commission authorize deferred accounting treatment for these three categories for the test year. The Staff conditioned its recommendation on the approval of four stipulations, which Consumers indicates it agrees to as well. The four stipulations are as follows:

> **Stipulation #1**: The Company shall provide a list of sub-programs and investment categories within each of the five programs of New Business, Demand Failures, Asset Relocation, Reliability, and Line Clearing and communicate any significant changes to these sub-programs and investment categories to Staff while the changes are still in the planning stages and prior to the implementation of the proposed changes – even if these changes occur at the end of a prior case. For example, prior to the instant rate case filing, the Company changed Imminent Demand Failures from the Demand Failures program to the Reliability program.
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> **Stipulation #2**: The Company shall provide quarterly spend reporting in each of the five programs throughout the test year and notify Staff of any anticipated spending above 110% of the approved spend amount for Distribution New Business, Distribution Demand Failures, and Distribution Asset Relocation programs. Each notification must include an explanation for the overspend.
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> **Stipulation #3**: The Company shall spend the full amounts approved by the Commission in Reliability and Line Clearing programs in order to receive deferred accounting treatment for an overspend, and the deferred accounting treatment must be symmetrical. If the Company spends the approved amounts in the Reliability and Line Clearing programs, deferred accounting treatment shall be authorized for both the overspend and the underspend (two-way tracker). If the Company fails to spend the approved amounts in either the Reliability or Line Clearing programs, or both, deferred accounting treatment shall only be authorized for the underspend (one-way tracker).
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> **Stipulation #4**: Deferred accounting treatment shall be requested for approval in each future rate case.

8 Tr 4883-4884. The Commission adopts the proposed four stipulations. The Commission's decision is based on the fact that, as Consumers says (and the Staff and the MEC Coalition agree),

these represent “unplanned” investments over which the utility lacks direct control. Deferred accounting treatment will protect ratepayers in the case of an underspend if the economy does not rebound sufficiently or housing starts taper off again, and will provide a form of monitoring and reporting, as the stipulations show. The Commission adopts the proposed regulatory asset treatment for all three categories.

b. Reliability (Lines 8-22, 23)

Consumers projects capital expenditures of $230,207,000 for 2019, $201,165,000 for 2020, and $331,234,000 for 2021 for its Reliability program. The Reliability program contains 14 subprograms, half of which are reliability subprograms (totaling $157.5 million for the test year) and half of which are rehabilitation, grid modernization, and other subprograms (totaling $173.8 million for the test year). Two issues are addressed, including the MEC Coalition’s overall reduction.

The MEC Coalition argued that 50% of the company’s request for the reliability subprograms for the test year ($78.7 million) should be disallowed, in order to bring this amount more in line with the 2020 projection of $82.5 million. The MEC Coalition argued that these programs are discretionary and the proposed spending is significantly higher than in the past, and again noted the effect of the pandemic on the economy. The MEC Coalition recommended that Consumers move towards “a condition-based replacement paradigm for its Reliability subprogram, as opposed to an age-based replacement paradigm.” 8 Tr 3662.

The ALJ recommended approval of the MEC Coalition’s overall proposal to reduce test year spending by half as a way to set just and reasonable rates. PFD, p. 48. The ALJ noted that Consumers’ proposal for 2021 is almost double the proposal for 2020, and that Consumers provided testimony indicating that the spending is discretionary and non-reactive. 6 Tr 1133. As with New Business, the ALJ found the MEC Coalition's concerns regarding the effect of the pandemic to be credible and not speculative. The ALJ recommended approval of $82.5 million for 2021, a reduction of $75 million from the proposal. PFD, p. 49.

As above, in the event that the Commission declines to adopt the MEC Coalition's overall adjustment, the ALJ went on to evaluate the specific line-item adjustments within Reliability proposed by the Staff, the Attorney General, the MEC Coalition, and JCEO.

In exceptions, Consumers contends that the MEC Coalition's arguments are based on unsupported policy preferences and that the proposed 50% reduction is arbitrary. Consumers notes that the Commission's decisions must be based on record evidence. MCL 24.285; Const 1963, art VI, sec 28. Consumers asserts that the MEC Coalition's arguments about age-based programs are wrong, noting evidence showing that the company replaces assets based on a variety of condition-based assessments. 6 Tr 1343-1346. Consumers argues that the test year levels sought in this case will not actually keep up with deterioration on the system. 6 Tr 1340. Consumers further argues that the ALJ engaged in speculation that the pandemic will result in a prolonged economic downturn and failed to rely on record evidence. Consumers again contends that 2021 and 2014 have no real connection, and the MEC Coalition failed to present any evidence addressing the effect of the proposed cuts on overall system reliability.

In reply to Consumers, the MEC Coalition argues that the Reliability program consists of discretionary, non-emergency, planned projects that may be re-prioritized. The MEC Coalition contends that the 2021 projected budget should be halved to bring it in line with the projected 2020 year budget, and as a way to set just and reasonable rates and to properly balance utility and ratepayer interests. The MEC Coalition contends that it is lawful and appropriate for the Commission to consider expert opinion testimony on matters of public policy, and notes that

Consumers has cited no precedent that holds otherwise. The MEC Coalition further posits that even the most granular and transparent proposal must still be reasonable and prudent, and questions whether it is necessary to maximize reliability spending at this time. The MEC Coalition also argues that it is reasonable to reduce the spending projection on a percentage basis, in light of the high number of projects and the elective nature of the projects included in the program.

For the reasons discussed above with respect to New Business, the Commission declines to adopt the MEC Coalition's overall proposed spending reduction based on the 2014 spend and the 2020 projection. The Commission finds that Consumers adequately supported its projections with information about the subprograms and about the deterioration of the distribution system, and showed that its projections are within a reasonable range of 2014-2020 spending. 6 Tr 1132-1220, 1044-1049; Exhibit A-150. Additionally, the Commission observes that there are times when historical averages are less useful than they would be otherwise, such as when it becomes necessary for the utility to make significant upgrades or adopt new technologies.

The Commission addresses the proposed line item reductions herein.

The MEC Coalition also proposed a reduction of 25% to the rehabilitation portion of the Reliability subprograms. Exhibit A-29, lines 18-21. Consumers projected a total of $95.5 million for the test year. The MEC Coalition's argument was based on the need to balance service quality with rate affordability. 8 Tr 3654-3655.

The ALJ noted that information about historical spending was not readily available in this cost category, and she recommended rejection of the MEC Coalition's proposal, finding that "many of the projects in this category are meant to address assets at risk of imminent failure and thus are not discretionary." PFD, p. 50. She also noted that Consumers had reclassified some of these costs, such that they will no longer receive deferred accounting treatment.

No exceptions were filed, and the Commission adopts the findings and recommendations of the ALJ.

i. Lines Reliability- High Voltage Distribution (Line 9)

The Lines Reliability-HVD subprogram consists of HVD line rebuilds, pole-top rehabilitations, pole replacements, and switch projects. 6 Tr 1144. Spending for this subprogram in 2018 was $42.71 million, and the projected 2019 and 2020 expense is $48.1 million and $16.3 million, respectively. This cost category has a five-year average of $27.8 million. For the test year, Consumers projects $78.13 million in capital expense, a $50 million increase over the five-year average. Two issues are addressed.

The Staff proposed that the Commission disallow $4,536,000 for 2020 and $15,936,000 for 2021 for the Lines Reliability-HVD subprogram, on grounds that the company failed to identify specific projects it intended to undertake at the time it filed its application, but instead used placeholders and bolstered its evidence on rebuttal. 8 Tr 4902; Exhibit S-13.5.

The Attorney General recommended a reduction of $19,084,000 for the test year only, based on a calculation of the average historical unit cost for line rebuild ($421,000), pole top rehabilitation ($75,973), and pole replacement ($18,235), multiplied by the number of each of these units the company expects to replace or complete in the test year. Exhibit AG-1.7; 8 Tr 3354.

On rebuttal, for this issue and many similar issues, Consumers disputed the accuracy of unit cost calculations and the efficacy of their use, and disputed the characterization of any of its projections as placeholders. As discussed above, Consumers emphasized the fact that exact amounts and specific projects cannot always be identified by the date of the application in a rate case.

The ALJ recommended adoption of the Staff's proposed reduction for 2020, stating:

> The ALJ agrees with Staff that the $4,536,000 downward adjustment for 2020 is reasonable and should be adopted. As the Staff points out, providing a fill-in-the-blank rate application is not in keeping with the letter or the spirit of MCL 460.6a(1), which provides that "[t]he utility shall place in evidence facts relied upon to support the utility's petition or application to increase its rates and charges, or to alter, change, or amend any rate or rate schedules." The PFD concurs with the Staff that permitting the company to update its projections over the course of the proceeding would allow for the filing of an incomplete application and could effectively sanction the filing of improper rebuttal. Moreover, the fact that many of these projects cannot be identified so far in advance could be remedied, at least in part, if the company were to adjust its test year to begin when its files its application, as the RCG suggests. As noted above, reasonable and prudent costs incurred after the company's initial filing may be included in the company's next rate case once they have been reviewed.

PFD, p. 54. The rationale articulated here underlies many of the ALJ's recommendations respecting rate base issues.

Additionally, the ALJ recommended adoption of the Attorney General's proposed test year reduction of $19.084 million, based on a comparison to the average cost. The ALJ noted that a number of projects in the initial filing were placeholders for which Consumers conceded it could not provide detailed information, because the projects had not yet been identified. PFD, pp. 54-55. In sum, the ALJ recommended a reduction of $4,536,000 for 2020 as proposed by the Staff, and, if the Commission does not adopt the $75 million test year adjustment to the Reliability subprogram discussed above, she recommended a reduction of $19,084,000 for 2021 for the Lines Reliability-HVD subprogram as proposed by the Attorney General.

In exceptions, Consumers states that it updated this projection in discovery in April 2020, two months before the Staff's direct testimony was due. 6 Tr 1326. However, Consumers also argues that even if the information had been updated on rebuttal that should not be considered "too late" as the ALJ suggested because there remains time for discovery and for cross-examination in the case. Consumers further explains that at the time it filed its application in this case, it was not possible to identify all pole and switch replacements, which have a short lead time. 6 Tr 1325-1326. Again, referring to its rolling approach, the company states:

> Therefore, for these shorter lead time projects, the Company left room for yet to be identified projects based on the Company historical experience for this subprogram. The updated projects and spending amounts provided to Staff in discovery, and as provided by Company witness Blumenstock in rebuttal, establish that the Company's rolling approach to identifying pole replacements and switch replacements will result in the Company spending the amounts initially projected for 2020 and 2021 in this proceeding.

Consumers' exceptions, p. 22.

Moreover, Consumers argues, the Staff's proposed numbers are outdated because the company showed on rebuttal that all spending for 2020 for this program is now attached to specific projects. 6 Tr 1326; Exhibit A-143. Thus, Consumers argues, the company's initial projections were clearly reasonable because later updates have shown them to be. Consumers posits that the ALJ considered the impact of the pandemic only if it had the potential to lower Consumers' projections. Turning to the Attorney General's proposed 2021 number, Consumers again argues that the unit cost approach will not work here because "[d]istribution investment projects are not commodities or an undifferentiated mass of goods." Consumers' exceptions, p. 25; 6 Tr 1384. Consumers faults the Attorney General for failing to account for inflation or cost trends in her historical analysis. Finally, Consumers argues that on rebuttal it had assigned all but $3.173 million of test year costs to a specific project.

In reply to Consumers, the Attorney General argues that her approach is reasonable and was based on the information that was known at the time that her witness's testimony was filed.

For the reasons discussed in Section III.A.2.a.i., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

ii. Substation Reliability- Low Voltage Distribution (Line 10)

Consumers projected capital expenditures of $11.5 million and $15.5 million for 2020 and 2021, respectively, for this subprogram addressing LVD substation reliability. This line item includes six categories of expenses, including mobile substations, animal mitigation, and substation rebuilds. Three issues are addressed.

The Attorney General calculated the average per unit cost for mobile substations for 2015-2019, and determined that the average cost per substation was $1,260,000. Multiplying this amount by the number of units projected to be acquired in 2020 and 2021, the Attorney General proposed reductions to this cost category of $1,260,000 for 2020 and $2,100,000 for 2021. 8 Tr 3355-3356; Exhibit AG-1.9. The Attorney General argued that Consumers did not provide sufficient support for the unit cost increase for mobile substations in the bridge and test years.

Likewise, for animal mitigation, the Attorney General calculated a unit cost of $45,174 per animal mitigation project for 2017-2019, and, applying the same multiplication, proposed a reduction of $996,000 for 2020 and $2,195,000 for 2021. 8 Tr 3356. Again, the Attorney General argued that the significant per-unit cost increase was not supported.

The MEC Coalition proposed a disallowance of 50% of the cost of three of four substation rebuilds, which amounted to a proposed reduction of $2.25 million, because Consumers failed to appropriately consider non-wires alternatives (NWA) as a potential solution to the need for the rebuilds.

The ALJ found that it was reasonable to rely on an historical, multi-year average in determining the cost of animal mitigation projects, and recommended adoption of the adjustment to this category for 2020, and, if her recommended overall adjustment is not adopted, then adoption of the adjustment for the test year as well. PFD, p. 58.

The ALJ recommended rejection of the other two proposals. She found that mobile substations are essentially "bespoke" items for which an average does not work well. *Id.* She further found that Consumers provided sufficient evidence to support its investments in the substation rebuilds, and a reasonable justification for not considering an NWA solution, based on the primary purpose of the rebuilds. PFD, p. 58.

No party filed an exception regarding these three issues and the Commission adopts the findings and recommendations of the ALJ and approves the adjustments to the animal mitigation projections for the bridge and test years. PFD, p. 58.

iii. Repetitive Outages-Low Voltage Distribution (Line 13)

The purpose of the Repetitive Outages-LVD subprogram is to strengthen areas of the LVD system where customers experience five or more interruptions annually. 6 Tr 1183-1184.

The Staff proposed reductions of $5,355,000 for 2020 and $7,672,000 for 2021 for this subprogram on grounds that many of these are placeholder projects. The Staff explained that the proposed 2020 disallowance is for 179 projects "with locations to be determined," and, for 2021, the Staff identified 300 projects where the project itself has not been identified. 8 Tr 4903.

The ALJ recommended adoption of the Staff's proposed adjustments, in the event that the Commission declines to adopt the overall reduction recommended above. PFD, p. 60.

In exceptions, Consumers argues that it must rely on the most recent possible data to identify the circuits that are the target of these projections, which necessarily means that the specific projects cannot be known much in advance. 6 Tr 1326-1327. The company argues that by using its rolling approach it has been able to identify additional projects for 2020 not included in its application. 6 Tr 1328; Exhibit A-144.

For the reasons discussed in Section III.A.2.a.i., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

iv. Grid Modernization (Lines 16, 17, and 54)

Consumers requests $44.5 million and $60.4 million for the Grid Capabilities: Automation subprogram in 2020 and 2021, respectively. This subprogram consists of four projects, including line sensors and regulator controllers. 6 Tr 1170; Exhibit AG-1.10. In addition, the company projects $19.9 million and $7.8 million for the Grid Capabilities: Advanced Technologies subprogram in 2020 and 2021, respectively. The projects included in the Advanced Technologies subprogram include Advanced Distribution Management System (ADMS), Distributed Energy Resources Management System (DERMS), and grid operational analytics. Finally, Consumers proposes to spend $1.4 million in 2021 on the Grid Technologies sub-program. Consumers also projected $1.35 million for a project to photograph system assets and store them in a geographic information system (GIS) for employees. The Attorney General, the MEC Coalition, and JCEO dispute some of the proposed spending in these subprograms. Several issues are addressed.

The Attorney General proposed reductions based on her calculation of the average cost per unit for 2017-2019 of line sensors and regulator controllers. Exhibit AG-1.11. The Attorney General also opposed the GIS proposal based on a lack of evidentiary support. In total, the Attorney General recommended disallowances of $5,213,000 for 2020 and $5,406,000 for 2021 for the three Grid Modernization subprograms.

The ALJ recommended rejection of the Attorney General's proposals based on finding that Consumers provided sufficient support for its spending in these categories. The ALJ found the

GIS proposal to be reasonable and prudent, and found that the unit cost approach did not work well with these cost categories. PFD, p. 63.

No exceptions were filed, and the Commission adopts the findings and recommendations of the ALJ regarding the Attorney General's proposed reductions.

The MEC Coalition and JCEO opposed implementation of ADMS and DERMS, which had a projected cost of $5.9 million and $1.184 million in the test year, respectively. The MEC Coalition criticized Consumers' distribution planning and argued that all 2021 spending on these two programs should be disallowed. The MEC Coalition argued that Consumers has no real plan in place today for putting these programs into operation, and suggested that a small pilot could be run, using shareholder funds. 8 Tr 3862. JCEO opposed spending on DERMS. JCEO argued that operation of the program is not sufficiently defined in the proposal, and that the current level of distributed energy resources (DERs) on the utility's system is so limited that the program is not warranted at this time. 8 Tr 4428-4429.

The ALJ recommended disallowance of the DERMS expense of $1.184 million in the test year on grounds that DER penetration is simply too low, and Consumers did not provide sufficient detail on the operation of the program. PFD, p. 66. The ALJ averred that the company will end its distributed generation (DG) program once the 1% cap is reached, and this will delay the need for DERMS. The ALJ recommended approval of the ADMS projection, finding that the company provided sufficient support for this program.

In exceptions, Consumers argues that it is not too soon to invest in DERMS. Consumers explains that it is proposing this phased-in approach so that the company can develop some capabilities before DER penetration gets higher. 6 Tr 1411. Consumers argues that the MEC Coalition and JCEO simply have preferences about how DERs are operated and controlled, and emphasizes that the company looks to gain information about how DERs can participate on Consumers' system. Consumers also argues that the MEC Coalition has objections to Consumers' broader distribution planning strategy, but that this should not prevent the company from implementing DERMS. 6 Tr 1166-1179. Finally, Consumers contends that once the 1% cap is reached, small solar facilities will still have the option to sell their excess power to Consumers at the standard offer price set pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA), and may also be eligible to sell their excess power at the market price of energy described in Rule C11 of the proposed tariffs in this case. *See,* 4 Tr 580.

In reply to Consumers, JCEO argues that the ALJ thoroughly considered Consumers' arguments before rejecting them, and notes that DER penetration is very low. JCEO points to the ALJ's finding that the operation and control function of the program lacks a plan, and explains that, "absent such a plan, customers risk paying for a technology that will, at some point in the future, be used to control their DER, without any assurance that the Company will manage those resources reasonably or compensate them fairly for the services their resources provide to the Company." JCEO's replies to exceptions, p. 12.

In reply to Consumers, the MEC Coalition acknowledges that the ADMS and DERMS programs represent foundational technologies for an integrated distribution system, but argues that Consumers "did not provide clarity or explanation for how its reliability or emergent customer demand programs will benefit from or be integrated with these systems." MEC Coalition's replies to exceptions, pp. 38-39. The MEC Coalition argues that these programs are actually not integrated into the distribution system and are not aligned with other modernization and distribution investments.

For the reasons articulated in the PFD, the Commission adopts the findings and recommendations of the ALJ. The Commission agrees with the ALJ that Consumers' proposal lacked clarity, and the company failed to explain how reliability would benefit from the DERMS program or how the information that will be generated from the program will then be integrated into the reliability program. *See,* 8 Tr 3859-3863. Additional planning, including details on the sequencing of DERMS and other technologies to enhance system monitoring and controls and their integration with existing systems such as Consumers' outage management system, AMI, and distribution supervisory control and data acquisition, is needed and prudent to pursue while DER penetration is still low. The Commission also notes that it may be valuable to further understand the evolving role and expectations of the distribution utility under the Federal Energy Regulatory Commission (FERC) Order 2222[6] when planning and designing new systems of this nature. The Commission encourages Consumers to include additional detail about how DERMS and other technologies will be sequenced and utilized to the benefit of its customers as part of its distribution investment and maintenance plan to be filed by September 30, 2021, including the opportunity for other stakeholders to comment on those plans as part of the draft plan shared by August 1, 2021. *See*, August 20, 2020 order in Case No. U-20147 (August 20 order).

v. Lines and Subs Rehabilitation-High Voltage Distribution (Line 18)

Consumers projected capital expenditures of $14,222,000 for 2020 and $38,921,000 for 2021 to rehabilitate and replace HVD lines, substations, and related equipment.

The Staff recommended an increase of $1,080,000 for 2020 and a reduction of $12,681,500 for the test year for the Lines and Substations Rehabilitation-HVD subprogram, based on the

[6] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172 FERC ¶ 61,247 (September 17, 2020) (FERC Order 2222).

presence of unidentified placeholder projects. The Attorney General proposed a reduction of $4.9 million for placeholder projects (this amount was also encompassed within the Staff's proposed reduction).

The ALJ recommended adoption of the Staff's proposal, consistent with the reasoning set forth above regarding placeholder projects and the lack of support for proposals within the original filing by the applicant. PFD, pp. 54, 67. The ALJ recommended adoption of the Staff's proposed increase of $1,080,000 for 2020 and reduction of $12,681,500 for the Lines and Substations Rehabilitation-HVD subprogram for the test year.

In exceptions, Consumers responds that all of the projects in this subprogram are intended to address issues where failure is imminent. 6 Tr 1193-1194. The company states that identifying projects too far in advance may have negative consequences. 6 Tr 1329-1330. Consumers maintains that the projection is based on experience with relatively consistent year-over-year imminent failures and actual failures. Consumers notes that on rebuttal it identified additional test year projects not specified in the application. 6 Tr 1331; Exhibit A-145. Consumers contends that the Staff has not demonstrated why the rolling approach must be rejected.

In reply to Consumers, the Attorney General urges disallowance of this placeholder amount.

For the reasons discussed in Section III.A.2.a.i., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ, including the Staff's proposed increase for 2020.

vi. Substation Rehabilitation-Low Voltage Distribution (Line 19)

Consumers projected capital expenditures of $14,500,000 for 2021 to rehabilitate and replace transformers and related equipment that are at risk of failure.

The Attorney General recommended a $3.0 million reduction, on grounds that six of the transformers do not need to be replaced in 2021. Consumers countered that not every project in this category addresses imminent failure, and that the six transformers are subject to regulations under the National Electric Safety Code (NESC). 6 Tr 1392.

The ALJ recommended rejection of the Attorney General's proposal on grounds that the six transformers at issue are out of compliance with the NESC. PFD, p. 68.

In exceptions, the Attorney General argues that the company has not made a convincing case that the six transformers in question need to be replaced in 2021 because of an imminent threat of failure. 8 Tr 3361. The Attorney General contends that the ALJ failed to consider whether the replacements need to occur in 2021, and argues that Consumers did not provide any information indicating the severity of the violations, or explaining why the replacements must occur in the test year. The Attorney General posits that these transformers have been in place for many years and presumably out of compliance for much of that time. The Attorney General proposes the $3 million reduction to this cost category.

In reply to the Attorney General, Consumers argues that not every project in this subprogram involves replacing transformers, and not every project is required based on an imminent failure. 6 Tr 1391-1392.

The Commission agrees with the ALJ and adopts her findings and recommendations. As Consumers showed, the working clearing code violation projects at the six substations are mandated by NESC regulations. *Id.* The Commission is not persuaded by the Attorney General's argument that, if a piece of equipment has presumably been non-compliant for a long period of time, it should be left that way. The Commission finds that Consumers adequately supported the projected amount.

vii. Lines Rehabilitation-Low Voltage Distribution (Line 20)

Consumers stated that the LVD Lines Rehabilitation subprogram includes repair or replacement of LVD lines equipment at imminent risk of failure. 6 Tr 1208. The company is projecting capital expense of $20,597,000 for 2020 and $37,723,000 for 2021 for this subprogram.

The Staff recommended a reduction of 2020 capital expense by $7.084 million, and a reduction of test year capital expense by $11,893,000, on grounds that these amounts have no projects associated with them and work purely as placeholders. 8 Tr 4905; Exhibit A-42, p. 26; Exhibit S-13.10, S-13.9. Again, based on a unit cost calculation, the Attorney General also proposed a reduction of $4,416,000 for 2020 and $12,980,000 for 2021.

The ALJ recommended adoption of the Staff's proposed adjustments, based on the company's use of placeholders. PFD, pp. 54, 70-71.

In exceptions, Consumers argues that this cost category includes two investment categories, one of which can be identified in advance and the other cannot. Consumers argues that the imminent rehabilitation investment category targets situations involving imminent failure that arise outside the normal inspection cycle, which can only be found on a rolling basis and have short lead times. 6 Tr 1332. Consumers also notes that it updated this 2020 projection on rebuttal. 6 Tr 1333; Exhibit A-146.

In reply to Consumers, the Attorney General urges disallowance of this placeholder amount.

For the reasons discussed in Section III.A.2.a.i., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

viii. Grid Storage (Line 22)

Consumers projected capital expense of $5.0 million in 2020 and $10 million in 2021 for the Grid Storage subprogram. This subprogram includes three battery installation projects at Cadillac, Fort Custer, and Standish. 8 Tr 4423-4424. Several issues are addressed.

JCEO supported the battery projects, but proposed that Consumers be required to better define the intended outcomes from pilot proposals, and clarify how pilot battery programs will lead to large-scale deployment. Consumers countered that it has been actively participating in the pilot's workgroup in the Commission's MI Power Grid initiative, and these issues are being addressed in that forum.

The ALJ agreed with Consumers and recommended that these issues not be addressed in this rate case. PFD, p. 70.

No party filed exceptions and the Commission adopts the findings and recommendations of the ALJ.

The Attorney General and the MEC Coalition proposed reductions to the projected costs. Noting that batteries are not selected in Consumers' IRP until 2032 at the earliest, the Attorney General argued that the entire test and bridge year amounts should be disallowed, or alternatively that the $10 million for 2021 should be disallowed.

The MEC Coalition supported the Cadillac and Fort Custer projects, but argued that the Standish portable battery project should be disallowed on grounds that this $8.1 million project will defer only about $3 million in upgrade costs, thus showing no cost benefit. The MEC Coalition contended that "the traditional alternative of upgrading the three substations has a significantly lower cost. Ultimately, the goal of infrastructure deferral should be to save money, thus the expectation of a battery storage pilot should be that the cost of the pilot nearly approximates the savings associated with deferral." 8 Tr 3657. Consumers countered that the goal of the project is to help the company develop the ability to use batteries as NWAs. 6 Tr 1351.

The ALJ recommended adoption of the MEC Coalition's proposal, finding that the MEC Coalition showed that the Standish project is expensive in comparison to the cost of repairing the substation. PFD, p. 73. The ALJ found that any delay should not impede Consumers' development and implementation of battery technology, and noted that batteries show a downward cost trajectory. *Id.*

In exceptions, the Attorney General argues for the full disallowance on grounds that there is insufficient evidence on the record to support this proposed expenditure. The Attorney General cites to the limited information that was supplied by the company in response to discovery, and lists the following reasons for adopting the full disallowance:

> First, [the company] stated that the estimated cost for battery storage is $4.9 million per MW [megawatt] based on a four-hour duration of storage capacity which objectively is a too high a cost given the very limited backup capacity provided. The Company did not provide any comparable cost data or any evidence that the cost [sic] were reasonable other than its "position." Second, it confirmed that in its 2018 IRP, the Company determined that batteries were not an economical electric supply solution until 2032 assuming significant improvement in performance and cost reduction. In this case, the Company did not demonstrate that batteries are economically competitive. Third, no information was provided about a planned large-scale installation of battery storage between 2025 and 2032. Fourth, the Company has already had experience with two battery storage pilot programs and has accumulated important lessons learned from those pilot programs, as identified in discovery response AG-CE-1004e. The Company has not explained how spending an additional $15 million between 2020 and 2021, with no economic solution in sight before 2032, adds anything of value to what is already known and therefore benefits ratepayers. Fifth, the Company would not provide any specific information to show how it arrived at the $10 million cost forecast for 2021. Sixth, the Company could not identify any near-term cost savings or financial benefits accruing to customers from spending $15 million over the next two years on additional pilot programs.

Attorney General's exceptions, pp. 7-8 (footnotes omitted). The Attorney General advocates disallowance of the full $15 million for the bridge and test years.

Also, in exceptions, Consumers argues that the ALJ erred in rejecting the Standish project, positing that the "goal of this project is to help develop the Company's ability to use batteries themselves as NWAs." Consumers' exceptions, p. 37. Consumers argues that it must take steps now to begin to develop capabilities in this area. 6 Tr 1351, 1375.

In reply to the Attorney General, Consumers argues that the Attorney General failed to provide any evidence to support her assertion that the company's estimated price is "very high," and also failed to offer a different estimated cost. 6 Tr 1393. Consumers also notes that the data on batteries in its last IRP was from 2017 and costs have fallen. Moreover, the batteries proposed for capital expense treatment are intended only as pilots. Consumers contends that it provided sufficient support for its cost estimate for 2021 in Exhibit A-42, p. 27, and Exhibit A-150, pp. 332-362. 6 Tr 1394-1395; Exhibit MEC-29.

In reply to Consumers, the MEC Coalition argues that Consumers has other ways to develop its ability to use batteries as NWAs, naming four other projects, and posits that deferring the Standish projected investment "is a reasonable way to balance an expensive learning project with a radically down-shifting economy." MEC Coalition's replies to exceptions, p. 46.

The Commission agrees with the ALJ and adopts the MEC Coalition's proposal to exclude the Standish project because, in light of the fact that Consumers has other pilot projects through which to gain experience, the Standish project appears to lack sufficient benefits given the need for the substation upgrades. The Commission also rejects the Attorney General's proposal to exclude the full bridge and test year amounts. The Commission finds that Consumers' remaining proposals were adequately supported.

The Commission recognizes that battery storage pilot programs cannot be evaluated purely on the basis of cost, because pilots have potential ancillary benefits that go beyond a short-term cost comparison. In particular, battery storage pilot projects are crucial in helping utilities develop the capability to construct and operate the battery systems that are going to be a critical component of energy supply in the near future. The Commission observes that, in response to the October 29, 2020 order in Case No. U-20645, wherein the Commission suggested a number of minimum objective criteria required to accompany pilot proposals, several comments were filed by the due date of December 11, 2020. Likewise, in the October 29, 2020 order in Case No. U-20898, the Commission officially launched the New Technologies and Business Models stakeholder workgroup as part of Phase II of MI Power Grid, and a status report from that group will be filed no later than September 1, 2021. Through these ongoing efforts, the Commission expects to provide further guidance with regard to evaluation frameworks for the review of pilots and energy technologies such as energy storage.

c. Capacity (Lines 24-33, 34)

Consumers requests approval of $66.323 million for the company's Capacity Program for the 2021 test year. Objections to the costs of specific subprograms are discussed below.

For programs not discussed below, the MEC Coalition proposed a 25% reduction, overall, for capacity.

The ALJ recommended rejection of the MEC Coalition's proposal, finding that the MEC Coalition did not adequately support the proposal. PFD, p. 73, n. 165; 8 Tr 3663.

No party filed exceptions and the Commission adopts the findings and recommendations of the ALJ.

i. Lines Capacity-Low Voltage Distribution (Line 24)

The Lines Capacity-LVD subprogram is intended to prevent overloads on the system that result from increased demand, load growth, or load shifting from one area to another. 6 Tr 1222. Consumers projected $11.3 million in test year capital expense for this program.

The MEC Coalition proposed a reduction of 50% to this program for 2021 on grounds that the company failed to consider NWAs or other targeted solutions for the subprogram, and also argued that the projection is based on incomplete information. The MEC Coalition argued that Consumers has a poorly performing integrated distribution planning process, and the company needs to look further into the future. 8 Tr 3874.

The ALJ recommended rejection of the MEC Coalition's proposal, finding that the MEC Coalition's broad concerns "are more appropriately addressed in the company's distribution planning case or in the MI Power Grid Stakeholder process." PFD, p. 75. The ALJ found that Consumers provided evidence that these projects are for upgrades to substations and lines that are already overloaded, and, in light of the short interval between when the company submitted its first distribution plan and the filing in this rate case, "it was unlikely that an adequate NWA alternative could have been timely evaluated and presented here." *Id.*

No party filed exceptions and the Commission adopts the findings and recommendations of the ALJ.

ii. Lines and Subs Capacity-High Voltage Distribution (Line 25)

The Attorney General recommended a reduction of $2,062,000 for 2021 capital expense in this subprogram on grounds that the company failed to identify the projects in its application and the projects are simply placeholders. The MEC Coalition agreed with this proposal.

The ALJ recommended adoption of the Attorney General's proposed reduction for the test year, for the same reasons articulated previously. PFD, pp. 54, 75. She again noted that reasonable and prudent spending in this subprogram may be included in the company's next rate case.

In exceptions, Consumers argues that the ALJ ignored the rebuttal evidence showing how this money would be spent and on which specific projects. 6 Tr 1395-1396; Exhibit A-153. Consumers argues that the Attorney General presented no evidence demonstrating that identifying projects on a rolling basis is unreasonable, and she failed to show that it is possible to identify these types of projects far in advance.

For the reasons discussed in Section III.A.2.a.i., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

iii. Substation Capacity-Low Voltage Distribution (Line 26)

The MEC Coalition recommended a reduction of $8.5 million to this program for five new LVD substations on grounds that these projects could be delayed. The MEC Coalition noted that in testimony Consumers stated that projects in this subprogram could be reprioritized and brought forward or, conversely, delayed.

The ALJ recommended that the MEC Coalition's proposal be rejected on grounds that it is speculative. PFD, p. 76. The ALJ found that the MEC Coalition failed to provide evidence to "show that a delay in these projects is likely, only that it is possible." *Id.*

No party filed exceptions and the Commission adopts the findings and recommendations of the ALJ.

iv. New Business Capacity-Low Voltage Distribution (Line 28)

Consumers projected capital expense of $11,777,000 for the New Business Capacity-LVD subprogram for the test year.

Consistent with its proposal for the New Business Program using 2014 as the reference year based on its post-recession attributes, the MEC Coalition recommended a 43% reduction for this subprogram. The MEC Coalition noted that there was no spending on this subprogram in the 2014 reference year, and applied the same percentage reduction for this program (43%) as was used for New Business.

The ALJ recommended rejection of the MEC Coalition's proposal on grounds that, unlike the New Business, Demand Failures, and Asset Relocation programs, the New Business Capacity-LVD subprogram is not included in the deferred recovery mechanism. PFD, p. 77. She found that "[i]f spending on this subprogram is reduced due to a decline in economic activity, the company can reallocate the spending to other programs or subprograms." *Id.*

No party filed exceptions and the Commission adopts the findings and recommendations of the ALJ.

v. Interconnections-High Voltage Distribution Lines (Line 31)

Consumers projected capital expenditures of $2,062,000 for the test year for this cost category. Consumers described this new Interconnections-HVD Lines subprogram as intended to fund line work necessary to connect company-owned solar generation, the sites for which Consumers expects to identify in late 2020.

The Attorney General recommended disallowance of the $2,062,000 for 2021 for this subprogram. The Attorney General argued that the funding for these projects is premature, given that the installation sites have not been identified and thus the timing is also uncertain.

Consumers countered that this work is necessary for the company-owned solar generation resources that were approved in the company's 2019 IRP.

The ALJ recommended rejection of the Attorney General's proposal, finding that Consumers provided sufficient evidence regarding the process of acquiring the sites, and the generation was approved in the IRP. PFD, pp. 77-78.

In exceptions, the Attorney General argues that Consumers failed to identify where the interconnections are to occur in its application and failed again in response to discovery and in rebuttal. The Attorney General contends that the "inclusion of company-owned solar in the IRP does not give the Company a pass on demonstrating that its proposed expenditures are reasonable and prudent and will be incurred during the projected test year." Attorney General's exceptions, p. 9. She argues that this amount is premature.

In reply to the Attorney General, Consumers argues that these expenditures are related to the construction of company-owned solar generation acquired through its 2019 solar solicitation, which was part of the plan approved in the June 7 order, Consumers' latest IRP case.

The Commission adopts the findings and recommendations of the ALJ. Like the ALJ, the Commission finds that Consumers provided sufficient evidence to support this IRP-approved project. In its direct case, Consumers provided testimony detailing the competitive solar solicitation process, the IRP settlement agreement requirements, the company's plan for implementing the new solar capacity, the administration and timing of the solicitation, the role of the independent administrator, and the associated costs. 6 Tr 1547-1551. The Commission finds that the projected expense was duly supported and declines to adopt the Attorney General's proposed reduction.

d. Demand Failures (Lines 35-42, 43)

Consumers requested approval of $122.6 million for the Demand Failures program in 2021. This program addresses emergent customer interruptions and equipment failures.

The MEC Coalition proposed a reduction of 25% overall for this program, taking the projected expense to $91 million. The MEC Coalition argued that Consumers' projection is overstated because the company has increased its ability to monitor its assets, has increased spending on the rehabilitation of assets at risk of failure, and has expanded its line clearance program. 8 Tr 3662-3663.

The ALJ recommended adoption of the MEC Coalition's proposal, finding that "additional spending on line clearance and rehabilitation should reduce the amount required for the Demand Failures program. In addition, any over- or underspending on the program will be captured and addressed by the regulatory asset/liability treatment for this program." PFD, p. 78.

The ALJ further stated that, in the event the Commission does not adopt this overall adjustment, the individual subprogram adjustments are discussed below.

In exceptions, Consumers makes the same criticisms of the MEC Coalition's policy-based approach to these proposed deep cuts as it made with regard to New Business and Reliability, describing this approach as speculative and arbitrary.

In reply to Consumers, the MEC Coalition again points to the expansion of Consumers' line clearance programs and other programs aimed at preventing outages to support its proposed overall reduction, arguing that it is reasonable to balance rate impacts against risk. The MEC Coalition notes that it supports regulatory accounting treatment for this area.

As with New Business and Reliability, the Commission declines to adopt the MEC Coalition's proposed overall cut. The Commission is not persuaded that the accomplishments of the company's forestry programs will mitigate the need for these proposed investments to the extent argued by the MEC Coalition. However, as discussed above in Section III.A.2.a.i., the Commission adopts deferred accounting treatment for Demand Failures, consistent with the Staff's recommendation and with the stipulations offered by the Staff. The Commission addresses the line items below.

i. Line Failures-Low Voltage Distribution (Line 35)

Consumers projected capital expenditures of $67,960,000 for 2020 and $78,538,000 for 2021 to address LVD line failures. Consumers explained that this program has two components: Service Restoration orders and Streetlight Failures. Exhibit AG-1.2.

The Attorney General proposed a reduction of $9.51 million for 2020 and $11,717,000 for 2021 in this subprogram based on the historical unit price of service restorations and streetlight replacements applied to the forecasted number of units for the bridge and test years. Exhibit AG-1.2, AG-1.3; 8 Tr 3350-3352. Consumers countered that a unit cost approach will not work, because the cost of any single service restoration can vary widely. Consumers noted that it is also replacing failed streetlights with light-emitting diode (LED) fixtures, which has increased the cost.

The ALJ recommended adoption of the Attorney General's proposed reductions. Noting that Consumers performs between 18,000 and 38,000 service restorations each year, the ALJ found that Consumers failed to show that service restorations in 2020 and 2021 will have an average cost any higher than the historical average. PFD, pp. 79-80. With respect to the streetlight replacements, the ALJ found that Consumers' LED streetlight replacement program is some years old now, and thus the increased cost of LEDs should be reflected in the historical numbers. The ALJ recommended adoption of the Attorney General's reduction of $9.51 million for 2020, and, if the Commission does not adopt the overall reduction to the Demand Failures program, she recommended adoption of the $11,717,000 disallowance for 2021. PFD, p. 80.

In exceptions, Consumers argues that the unit cost approach is inappropriate, since the "unit" is a service restoration order – something prone to wide variation in size and complexity. 6 Tr

1386. Consumers notes that LEDs increase costs, and argues that the Attorney General failed to put any evidence in the record showing when the LED replacement program started. Consumers argues that these are substantial cuts with no acknowledgement of the company's actual needs.

In reply, MAUI states that it agrees with Consumers' exceptions, "because the Attorney General's method for cost projection incorrectly assumes that past costs are accurate predictors of future costs." MAUI's replies to exceptions, p. 1.[7]

In reply, the Attorney General repeats her arguments for this proposed disallowance.

The Commission agrees with the Attorney General and adopts the findings and recommendations of the ALJ, including the disallowance for 2021. The Commission finds that the Attorney General made a convincing showing with respect to the unit cost. The Attorney General relied on the three historical years 2017 through 2019 for both calculations, which are the three most recently completed years. It would be difficult to calculate a more recent average. The Commission agrees with the ALJ that the company failed to provide a convincing explanation for the unit cost difference.

ii. Center-Suspended Streetlighting (Line 41)

Consumers proposed to undertake a program, beginning in 2021 and ending in 2029, to replace center-suspended streetlights with either cobra-head streetlights or post-top streetlights. Consumers explained that there are 11,000 center-suspended streetlights which, in the event of a failure, present traffic and safety concerns. 6 Tr 1114-1115; Exhibit A-33. Consumers proposed capital expenditures of $5 million to replace between 650 and 700 of these streetlights in the test year. As stated above, the lights themselves are being replaced with LEDs.

[7] Other issues concerning municipal streetlighting are discussed in Section VI.I., below.

The Attorney General and the Staff argued that Consumers failed to provide sufficient detail about the program. They noted that Consumers has not yet developed the database for prioritizing replacements and could not provide a list of the locations that will be addressed. According to the Attorney General, Consumers indicated that no replacements, and apparently no failures, occurred between 2014 and 2017; in 2018, the company replaced only 8 streetlights; and in 2019, it replaced 42 streetlights. Exhibit AG-1.4. The Staff questioned whether the benefits of the eight-year program meet or exceed the estimated $82.5 million total cost. The Staff proposed disallowance of the total program cost for this rate case. The Attorney General recommended an allowance of $315,000 for the program (a disallowance of $4,685,000), which assumes the replacement of 42 streetlights at $7,500 per light for the test year (consistent with 2019).

The ALJ recommended adoption of the Attorney General's proposed reduction, finding that Consumers had not provided evidence demonstrating that this accelerated program is reasonable. PFD, p. 82. Recognizing that Consumers will have to perform some replacements during the test year, the ALJ recommended rejection of the Staff's proposal of a total disallowance.

In exceptions, the Staff contends that the ALJ erred by not recommending the full $5 million disallowance. The Staff argues that Consumers failed to show that it has experienced any safety incidents related to the maintenance of center suspension lighting. 6 Tr 2435. The Staff contends that work within the roadway is inherently hazardous, and the new LED lights provide a benefit whatever their locations. The Staff argues that the program is justified by Consumers on safety grounds, but the company has shown neither a safety issue nor any benefits. "Allowing the Company to recover $315,000 to replace a few dozen center suspended streetlights with cobra head or post top streetlights would amount to approving overpriced luminaire changes or repairs."

Staff's exceptions, p. 5. The Staff argues that the Commission continues to need additional information to justify relocating the streetlights to the side of the road.

In its exceptions, Consumers argues that the ALJ ignored the evidence. Consumers contends that this is dangerous work and that no party showed otherwise, and it is also difficult work to schedule and execute. 6 Tr 1114-1116. Consumers states that one restoration may take up to six months, compared to five days for a cobra-head light restoration. *Id.* Consumers also argues that the approved amount of funding lacks a connection to reality, because the Attorney General based the calculation of 42 restorations on a discovery response addressing full replacements of a center-suspended light with an LED cobra-head or post-top light. However, based on its 15% failure rate, "the Company has a fleet of center-suspension streetlights of approximately 11,000 (6 TR 2437), that would mean that there are approximately 1,650 center-suspension streetlight failures per year that must be restored by at least some form of bulb replacement or other partial replacement." Consumers' exceptions, p. 47. Consumers states that its projected funding allows for the replacement of about 650 center-suspended lights per year, so that the fleet will be replaced within 17 years.

In reply, MAUI states its agreement with Consumers' exceptions.

In reply to Consumers, the Attorney General argues that her discovery request generated inconsistent information from the company, and notes that Consumers' exceptions do not identify the number of lights that failed and were replaced. Exhibit AG-1.4.

In reply to the Staff, Consumers argues that the Staff fails to appreciate the company's safety concerns and the degree of risk involved in working in the center of the road. Consumers points out that the ALJ noted the efficiencies involved in doing the conversion on lights that require service anyway, and argues that she was incorrect with respect to the annual number of needed conversions. Consumers describes this as a modest replacement program taking place over a reasonable 17-year period.

In reply to Consumers, the Staff argues that the company needs to provide additional information in a future database, or in some other format, to justify this program of relocating the streetlights to the side of the road.

The Commission agrees with the ALJ that Consumers has failed to sufficiently support the need for the proposed expenditures and for the program overall, and adopts her findings and recommendations. Consumers is certainly correct that a program need not demonstrate that it has associated fatalities in order to justify the need for safety enhancements, but in this case Consumers has failed to convincingly demonstrate the need for the projected amount. The Commission agrees with the Attorney General's proposed allowance which assumes the replacement of 42 streetlights during the test year. The Commission encourages Consumers to provide greater detail to justify a higher level of expenditure and replacement in future rate cases, at which time the Commission may reconsider whether greater expenditures are warranted.

iii. Metro Demand Failures (Line 42)

Consumers explained that the Metro Demand Failures subprogram involves the replacement of failed cables, transformers, and civil infrastructure within the company's six Metro systems. 6 Tr 116-117. Consumers projected $3.0 million and $3.1 million in capital expense for this subprogram in 2020 and 2021, respectively.

The Attorney General stated that in discovery Consumers indicated that it will only be spending $1 million in 2020, and she argued for exclusion of the remainder. 6 Tr 3354; Exhibit AG-1.5. Consumers countered that it had removed the extra $2.0 million for 2020, and had moved it to the Lines Rehabilitation Metro subprogram. 6 Tr 1387; Exhibit A-157.

The ALJ recommended adoption of the Attorney General's proposed reduction, finding that, "consistent with the other instances where the company has chosen to shift costs from one program or sub-program to another after its application has been filed, the company's request to maintain the $2.0 million expense as part of its overall distribution plan spending should be rejected." PFD, pp. 83-84.

In exceptions, Consumers argues that it should be allowed to shift this $2 million to the Lines Rehabilitation Metro subprogram because it has provided record evidence showing the need for the money for that subprogram. 6 Tr 1387; Exhibit A-157.

In reply to Consumers, the Attorney General argues the proposal to shift this money shows that the amount was a placeholder.

The Commission agrees with the ALJ that the company may not simply shift cost amounts during the rate case from one program to another, and adopts her findings and recommendations.

e. Asset Relocation (Exhibits A-26, A-34)

Consumers projected capital expenditures of $41,675,000 and $45,976,000 for the Asset Relocation Program in 2020 and 2021, respectively. This program includes capital expenses for the relocation of assets as a result of road building, construction projects, and the company's internal needs. Several issues are addressed.

Consistent with its recommendation for the New Business subprogram, discussed above, the MEC Coalition recommended an overall reduction of $26.6 million for this program (from $46 million to $19.4 million), based on 2014 total spending on this subprogram. The MEC Coalition noted that Consumers' proposal is an increase of $18.9 million over historical five-year average spending (2014-2018), and an increase of $20 million over the amount in current rates. The MEC Coalition argued that, because many of these projects are market-driven, the company's forecasts may be far more optimistic than warranted under the recessionary economic conditions which are likely to persist into 2021.

Consumers countered that new business has not been significantly affected by the pandemic, and that spending in some programs has rebounded since the Governor's stay-at-home order was lifted. 6 Tr 1355.

The ALJ recommended rejection of the MEC Coalition's proposal, finding that Asset Relocation was not analogous to New Business. The ALJ observed that, whereas New Business is closely tied to new customers (who likely have been, and will continue to be, significantly affected by the pandemic), Asset Relocation applies more to existing customers, road building projects, and internal company requests, which are less affected by the pandemic. PFD, p. 85. Assuming that it is approved, she also noted that the regulatory asset/liability accounting treatment for Asset Relocation will limit the risk to ratepayers, in the event that spending in this program is lower than forecast.

No exceptions were filed, and the Commission adopts the findings and recommendations of the ALJ. Consistent with the discussion above in Section III.A.2.a.i., the Commission approves deferred accounting treatment for this cost category.

The Staff proposed an adjustment to the Lines Relocations-LVD subprogram of this cost category. Exhibit A-26. Consumers projected capital expenditures of $36,585,000 for 2020 and $41,226,000 for 2021 for this line item. Exhibit A-34. The Staff recommended that the Commission disallow $5,688,000 for 2020 and $6,178,000 for 2021 for this subprogram. The Staff adjusted its 2020 disallowance to $1,688,000 after Consumers indicated that $4 million of its original request for 2020 had been moved to Lines Reliability-HVD to fund additional pole top work, although the Staff continued to advocate for the exclusion of the $4 million as well because the reallocation could not be reviewed. PFD, p. 86, n. 189; 6 Tr 1324. The Staff testified that no specific projects accompanied the $1.688 million line item for 2020, and that $6.178 million for 2021 is for "additional projects to be identified." 8 Tr 4898-4901. Noting that the Commission has previously found that unknown "emergent" expenditures should be disallowed, the Staff found these amounts to be placeholders. The Staff further noted that relocation requests usually involve planned investments, and thus argued that details should have been accessible.

The ALJ recommended adoption of the Staff's total proposed disallowances (including the reallocated amount) on grounds that these items are placeholders and are unidentified. PFD, pp. 87, 54.

In exceptions, Consumers argues that it should be allowed to shift the $4 million to the Lines Reliability – HVD subprogram, because the company has presented evidence supporting the need for the money in that subprogram. 6 Tr 1324-1325. Consumers also repeats its objections to the Staff's placeholder arguments, arguing that simply because a project is internally driven does not mean that the company knows about it several months in advance. Consumers contends that LVD work "emerges through the year to support the HVD work." Consumers' exceptions, pp. 50-51.

For the reasons discussed in Section III.A.2.a.i., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

f. Electric Other (Line 55)

Consumers projected capital expenditures of $11.4 million for the Electric Other subprogram in 2021. This program includes computers and equipment, tools, system control projects, and grid technologies.

Similar to its other proposals, the MEC Coalition recommended that test year capital expense for this program be reduced by 25% overall, or $2.8 million, to bring spending in line with 2019 spending (which was $7.5 million), and to, again, strike a proper balance between rates and service quality.

The ALJ recommended rejection of the MEC Coalition's proposal, finding that the Electric Other program is relatively small compared to other distribution programs, and spending in this cost category "is not necessarily discretionary." PFD, p. 87.

No party filed exceptions and the Commission adopts the findings and recommendations of the ALJ.

i. Tools (Line 49)

Consumers included capital expense of $5,691,000 for 2020 and $5,792,000 for 2021 for the Tools subprogram in the Electric Expense Other program.

The Attorney General proposed reductions of $2,231,000 for 2020 and $1,830,000 for 2021, based on the company's failure to explain the increase in the unit cost of this item compared to the average historical cost. 8 Tr 3367. The Attorney General noted that there are two components to the Tools subprogram: (1) Truck Tool Packages; and (2) Other Capital Tools. Calculating an average unit cost for 2018-2019 and multiplying by the number of projected units, the Attorney General posited that the 2020 amount for Truck Tool Packages was overstated by $1,120,000. 8 Tr 3367; Exhibit AG-1.17. For Other Capital Tools, calculating an average unit cost for 2017-2019, the Attorney General argued that the 2020 projection is 60% (or $1.111 million) above the average, and the 2021 projection is almost 100% ($1.830 million) above the average. 8 Tr 3368.

The ALJ found that Consumers provided "sufficient support" for the increased costs of these subprograms. PFD, p. 89 (citing 6 Tr 1250-1253). However, she stated:

> [T]he ALJ is nevertheless concerned that tools for new vehicles are included in both Distribution and in Fleet Services, raising an issue whether the costs of the same tools have been included in both of these programs. Even if there is not a double counting issue, [Consumers' witness] testified that some portion of tool capital spending relates to the company's "fleet acquisition and deployment plan." As discussed below, the company's fleet replacement and acquisition plans have been adjusted, thus, the need for additional tools for the truck tool packages should be reduced.
>
> Given the time constraints for issuing this PFD, which do not allow sufficient opportunity to scrutinize the record to determine the appropriate disallowance for tools (recognizing the adjustment to Fleet Services) the ALJ agrees with the Attorney General's recommendation to remove $2,231,000 for 2020 and $1,830,000 for 2021 from projected rate base for the Electric Other Tools subprogram.

PFD, p. 89 (footnotes omitted); 6 Tr 2122; Exhibit A-12, Schedule B-5.7.

In exceptions, Consumers first points out that the ALJ herself found that the company supported the projected costs, thus there is no reason on the record to adopt the Attorney General's proposed reductions. Second, Consumers asserts that the reductions are not an appropriate response to the issue of potential double counting, stating:

> The PFD points to no evidence in the record to establish that the Company has double counted costs by $2,231,000 for 2020 and $1,830,000 for 2021 in the Tools subprogram. The Company has not double counted costs. The PFD also points to no evidence which demonstrates that reductions to Fleet Services result in reductions of $2,231,000 for 2020 and $1,830,000 for 2021 in the Tools subprogram. The proposed reductions to Fleet Services do not result in such reductions to the Tools subprogram.

*Id.*, p. 53. Consumers objects to a decision based on "time constraints" and argues that it is not a reduction based on the evidence, as explained by the ALJ. Consumers urges the Commission to rely exclusively on the evidence.

In reply, the Attorney General argues that the ALJ's concerns are reasonable, though they are not based on the Attorney General's arguments, and states that, "while the Attorney General questions that it would be prudent to simply adopt her proposed disallowances if the Commission does not otherwise agree with the basis for Attorney General's recommendation, the Commission is not prohibited from disallowing any amounts that it does not believe are supported by the record." Attorney General's replies to exceptions, p. 23.

The Commission observes that the Attorney General's proposed disallowances were not based on an allegation of double-counting, and the ALJ conceded that time constraints were a factor in making her recommendation. The Commission agrees with the ALJ that Consumers presented sufficient support for the increased investments. Consumers explained in its direct testimony that spending on tools has been increasing because the company has been buying tool packages for trucks since 2016, and because tool prices have increased at a time when many of the company's tools (those which cost in excess of $1,000) have reached the end of their useful life. 6 Tr 1250-1253. Consumers is also investing in more ergonomic and high-visibility tools. The Commission approves the projected 2020 and 2021 capital expenditures for this subprogram.

ii. System Control Projects (Line 50)

The System Control Projects subprogram consists of projects that are intended to improve the operations of control centers, streamline operations, and improve remote control capabilities. 6 Tr 1254. Consumers projected capital expenses of $4,022,000 for 2020 and $4,170,000 for 2021 for this subprogram. Exhibit A-35.

The Staff proposed a reduction of $1,316,000 for 2020 and $2,305,000 for 2021, based on the presence of placeholders. 8 Tr 4907. The Attorney General recommended reductions of $1,316,000 for 2020 and $1,274,000 for 2021 based on the unit cost of various items within the subprogram. 8 Tr 3369. Consumers countered that it updated the company's case on rebuttal and that the unit cost approach is not appropriate.

The ALJ recommended adoption of the Staff's proposed reductions, on grounds that the identified amounts represent placeholders. PFD, pp. 90, 54.

In exceptions, Consumers argues that it established on the record that all of the projects for 2021 have been identified. 6 Tr 1333; Exhibit A-147.

In reply to Consumers, the Attorney General urges disallowance of this placeholder amount.

For the reasons discussed in Section III.A.2.a.i., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

g. Concept Approval

The Attorney General recommended a $107.7 million adjustment to the company's Distribution spending plan, based essentially on the inadequacy of concept approval. The Attorney General noted that the company listed hundreds of individual projects included in 2021 capital expenditures and in projected rate base, some of which had received concept approval by January 2020 and some of which had not. For 2021, the Attorney General argued that 27 projects should be disallowed, for a total of $107,697,000, on grounds that it is premature to "include the conceptual cost of such projects in rate base until they progress past the design stage and the cost and timing of the projects have been established with some certainty." 8 Tr 3371-3372; Exhibits A-41, A-42, AG-1.22, AG-1.21. Consumers countered that the concept approval documents are well-vetted and provide definition and scope.

The ALJ recommended that the Attorney General's proposed disallowance be rejected, finding that Consumers provided evidence showing that the listed projects have undergone "a significant engineering and cost review." PFD, p. 92. The ALJ found that "[t]he company's explanation of the 'concept approval process' for <u>distribution</u> projects makes clear that the resulting 'concept approval' is for projects that are not preliminary in nature and represent significant planning and cost estimating efforts for individual projects. Moreover, at the time rebuttal was filed, none of the costs had changed and all but two of the projects had received management approval." PFD, p. 93 (emphasis in original).

In exceptions, the Attorney General argues that the projected costs for these 27 projects should be disallowed. She contends that Consumers refused to provide copies of executed approval documents, failed to update cost estimates, and failed to provide similar concept approval documents for 2019 or 2020. Exhibit AG-1.21. The Attorney General contends that Exhibit A-41 shows that many of the projects have not even received concept approval, and it is unclear when or if these costs will be incurred. The Attorney General maintains that even on rebuttal the company failed to provide any supporting documentation, and the ALJ relied only on the statements of the company's witness. 6 Tr 1400. She argues that Consumers did not meet its burden to support these costs and the Commission should adopt her proposed $107.7 million adjustment for 2021 for these 27 projects. Exhibit AG-1.22.

In reply to the Attorney General, Consumers argues that the documents regarding concept approvals were provided by the company in this case only as examples of the concept approval process, to illustrate how investments are assured to be reasonable and prudent, and to increase transparency. Consumers further contends that it established on the record that the approval documents show well-vetted cost estimates. "The concept approvals define what the scope and cost of any given project are going to be for management approval. Therefore, a concept approval indicates that a project has gone through the Company's approval process, has been fully vetted by planning and design engineers, and is therefore a solid project, rather than a hypothetical or speculative project as the Attorney General infers." Consumers' replies to exceptions, p. 18; 6 Tr 1398. Consumers argues that mere use of the word "concept" does not mean that the project is speculative. 6 Tr 1398-1399; Exhibit A-41. Consumers reiterates that it has received several final management approvals, as shown on rebuttal. 6 Tr 1400.

The Commission adopts the findings and recommendations of the ALJ. Consumers made it clear in its direct case that these concept approval documents were intended to be "selected examples," and were not intended to provide documentation of all internal approvals or all engineering bases for the projects themselves. Exhibits A-41, A-42; 6 Tr 1068-1069. Additional detail was provided on rebuttal and the Commission agrees with the ALJ's assessment of the subprograms. 6 Tr 1398-1400.

h. Distribution System Planning

The MEC Coalition and JCEO criticized Consumers' approach to distribution planning, arguing that the company has failed to consider the grid benefits of DG in its overall distribution planning. The MEC Coalition recommended that the Commission provide additional guidance to the company in advance of the filing of its next distribution plan in September 2021, and made the following specific recommendations: "(1) future load forecasts should be based on AMI [advanced metering infrastructure] data and other data such as hosting capacity analysis; (2) load forecasts should be aligned between the distribution plan and the IRP; (3) the company's rate case distribution spending should be justified by, and aligned with, the 5-year distribution plan; and (4) the company should be required to consider non-wires solutions for substation projects over $1.5 million." PFD, pp. 93-94 (footnotes omitted); *see,* MEC Coalition's initial brief, pp. 51-52; 8 Tr 3878-3881. JCEO argued that the utility needs to do more than passively accommodate DER.

The ALJ agreed that the Commission should provide further guidance to Consumers in advance of the company's upcoming five-year distribution plan filing, but also found that "the recommendations by the MEC group and the JCEO are more appropriately addressed as part of MI

Power Grid initiative, or other forum, given the complex nature of distribution planning and the short timeframe available for completing a rate case." PFD, p. 94.

No party filed exceptions.

The Commission agrees with the ALJ's recommendation that the Commission should provide further guidance, and adopts three of the MEC Coalition's proposals, namely that: (1) future load forecasts should be based on AMI data and other data such as Consumers' hosting capacity analysis and its interconnection process; (2) load forecasts should be aligned between the distribution plan and the IRP; and (3) the company's rate case distribution spending should be justified by, and aligned with, the five-year distribution plan. *See,* 8 Tr 3867-3880. The Commission finds that the distribution planning effort has progressed to the point where the connections between the distribution plan and the capital investments described in the rate case need to be made clear and synchronized, and this need extends beyond the one- or two-year window of a rate case. A lack of information as to how Consumers' distribution planning measures translate into rate base investments undercuts the Commission's ability to discern whether the proposed investments are reasonable and prudent. As noted in the May 8 order, and repeated in the August 20 order, the "consideration of alternatives . . . are an important element in demonstrating why [a utility's] proposed expenditures are preferable to other options." May 8 order, p. 112; August 20 order, p. 42. Consumers must be able to demonstrate exactly how distribution capital expenditures align with its distribution investment and maintenance plan, what are the outcomes that can be expected from the capital investment, and how are the expected outcomes to be measured (a description of relevant metrics used by the company to measure performance). The Commission, while declining to adopt the MEC Coalition's fourth suggestion regarding considering NWAs for projects over $1.5 million in cost, notes that it recently agreed with the Staff that utilities should consider energy waste reduction (EWR) measures in upcoming distribution plans, in part because "a stronger linkage between EWR and DR efforts and distribution planning would facilitate the identification of potentially cost-effective NWAs that could defer [or] displace an expensive distribution upgrade." August 20 order, p. 50.

Consumers' next distribution investment and maintenance plan is due to be filed no later than September 30, 2021, with a draft shared with other stakeholders by August 1, 2021. *Id.,* p. 51. The Commission recognizes that Consumers' next rate case is likely to be filed well before that date. However, in future rate case filings, the Commission directs Consumers to provide information in these three categories tied to Consumers' then-current distribution plan. *See,* Case No. U-18014, filing # U-18014-0034, January 31, 2018 Distribution Operations Five-Year (2018-2022) Investment and Maintenance Final Report. While this may be challenging given the potentially short timeframe involved, the Commission encourages Consumers—to the extent practicable—to anticipate how specific distribution elements filed as part of a rate case filed prior to its 2021 distribution investment and maintenance plan will align with the company's forthcoming distribution investment and maintenance plan. This effort should be easier and even more granular in the rate case that is filed after the September 2021 filing, and the Commission expects that rate case filing to provide the required information. The Commission recognizes that additional effort may be needed to fully utilize AMI data for load forecasting and expects updates on this effort to be included in the distribution plan to be filed in 2021.

i. System Average Interruption Duration Index Glidepath

Consumers explained that it uses the System Average Interruption Duration Index (SAIDI) as its principal measurement of reliability. SAIDI represents the average number of minutes per year that a typical electric customer is without electric service. 6 Tr 1049. SAIDI is measured by

Consumers excluding major event days (MEDs), to normalize data by removing storm activity that can vary from year to year. 6 Tr 1049-1050. Consumers indicated that the spending levels presented in this case "will put the Company on a glidepath to a SAIDI performance of approximately 170 minutes, excluding MEDs, by 2025, a reduction of 28 minutes from the 2020 projected performance of 198 minutes." 6 Tr 1038. However, this is a significant step back from the projected 120 minutes by 2022 included in Consumers' 2018 EDIIP.

At the conclusion of a general discussion of SAIDI, the ALJ indicated that, as discussed in more detail below, she declined to adopt performance-based regulation (PBR) in this proceeding. She suggested that the Commission consider including a reliability metric as part of any PBR mechanism that may be adopted. PFD, p. 97.

In exceptions, the Attorney General urges the Commission to reject the ALJ's recommendation to do nothing, and recommends that any increase in expenditure be conditioned on Consumers achieving real results and being held accountable. The Attorney General points to the testimony of Consumers' witness, Mr. Blumenstock, in which he indicates that even this slower glidepath "does not represent a commitment to hit intermediate annual targets. . . . [I]f actual SAIDI performance in an intermediate year does not exactly track with the glidepath, this should not be interpreted as a failure to meet a goal." Exhibit AG-HR-5, p. 1.

In its exceptions, Consumers states that it addresses this issue in the PBR section, below.

In reply to the Attorney General, Consumers objects to the Attorney General's arguments on accountability, stating, "in general, Performance Based Regulation ("PBR") that considers reliability metrics, as Attorney General [sic] appears to suggest, should be well-designed through collaborative processes to balance various goals." Consumers' replies to exceptions, p. 23.

In reply to Consumers, the MEC Coalition states that it shares the Attorney General's concerns.

Issues respecting PBR are addressed in this order in Section VI.M., below.

3. Fossil and Hydro Generation Capital Expenditures

Consumers projected capital expenditures of $174 million in 2019, $119.6 million in 2020, and $161.1 million in 2021 for its generating plant, including coal and gas fueled steam generation, hydro, Ludington, and other plant. Exhibit A-12, Schedule B5.2. The Staff, the Attorney General, and the MEC Coalition took issue with several generation cost categories, discussed below.

Consumers explained that cost estimates have five class levels, class 1 through class 5, with class 1 being the most mature and class 5 the least. 6 Tr 2072. The classes reflect the corresponding high to low expected accuracy range for the estimate. *Id.* Consumers also explained that a typical project progresses through six gates in its life cycle, and some projects included in rate base are at project gate zero (the least mature). 6 Tr 2073.

By way of background for many of its objections, the Staff explained Consumers' project approval process, from project initiation to a signed project charter, and the relationship between project stages and the class of cost estimate assigned to the project. Exhibits S-17.1, S-17.2. As the Staff noted, project costs and scope become better defined as a project moves through each stage of the process. 8 Tr 4750-4753. The Staff identified the corresponding stage for each project, the class for each cost estimate, and the expected upper and lower bounds of confidence in the estimated overall project costs. The Staff also examined scoping documents (where available) and actual expenditures. All of this information informed the Staff's proposals regarding the maturity level and accuracy range of an expense projection. 8 Tr 4753-4757; Exhibit S-17.0. The

Staff also made a comparison of actual to projected expenditures from Consumers' most recent rate case, Case No. U-20134, which revealed a range from over-projections of 100% to under-projections of 25% in comparison to actual project costs. 8 Tr 4755. As was the case with distribution expenditures, the Staff argued that, for some generation projects, Consumers failed to provide adequate support for the projected cost, or provided support only on rebuttal, and the Staff recommended that the Commission rely on the low accuracy range.

Consumers objected to the Staff's approach, explaining that:

> Most of the projects for which Mr. DeCooman recommended a partial disallowance were at project gate zero or one, which includes documentation of a business case or project initiation. 6 Tr 2073. A typical project progresses through six gates through the project life cycle, and as such, the scope of documents and the level of estimates that were available at the time of Staff's review of the projects were not mature. *Id*. Therefore, Mr. DeCooman's reliance on the state of the supporting documents was without basis.[8]

Consumers' initial brief, p. 111.

The ALJ began her analysis of generation capital expenditures by stating:

> As reflected in the discussion of individual projects that follows, this PFD finds that Consumers' contention that it can present projects at project gate zero or one, missing sufficient support for approval, and attempt to supply the missing support in the rebuttal phase of this proceeding is fundamentally at odds with the standards the Commission has established for rate cases. The Commission has made clear that the utility is obligated to provide full support for its projections with its filing; this is even more critical in a 10-month rate case, in which the parties typically have less than two weeks to examine the rebuttal filings. The company's argument, as quoted above, constitutes an admission that it has presented immature projects as placeholders. The ALJ notes that if a utility wishes to allow the parties additional time to review new information that is not available until the rebuttal phase, the utility may extend the schedule. Otherwise, the supplemental information is inadequate to remedy the deficiency of supporting evidence with the initial filing.

PFD, pp. 101-102.

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[8] Mr. DeCooman was the Staff's witness on these issues.

In exceptions, Consumers responds that all of the generation capital expense disallowances recommended by the ALJ should be rejected. Consumers notes that many of the ALJ's decisions are based on acceptance of the Staff's argument that projections which fall within the low end of the accuracy range are unreliable. 8 Tr 4754. However, Consumers posits, "there is a low to zero probability that 100% of the projects would have an actual cost at the low end of the overall accuracy range." 6 Tr 2073.

In reply to Consumers, the Staff argues that this statement could be misleading. The Staff points out that, for the majority of the 14 projects for which the Staff recommended an adjustment based on the class of the cost estimate:

> [T]heir class of cost estimate are 'class one or zero,' and therefore represent projects that are the least defined in scope and subject to the most uncertainty. (Staff's Initial Brief, p. 32.) While an aggregate of costs for all projects in the Company's filing may be expected to fall around the total average estimate, this would include a vast majority of projects that are significantly further along in the development process, as represented by having a higher class of cost estimate. (See Exhibit S-17.3, which provides the class of cost estimate for each project in the Company's request.) It is not reasonable to assume that a much smaller sample size of projects, particularly those with less defined cost estimates, would follow this same trend. Even if one was to make such an assumption, reliance on such an assumption, particularly when approving projected expenses for inclusion in customer rates, does not meet the burden of proof that requires the Company support its estimates as reasonable and prudent.

Staff's replies to exceptions, p. 5.

As will be seen in the discussion of fossil and hydro generation capital expenditure herein, the Commission largely agrees with the Staff and the ALJ and generally finds that cost estimates falling within class one or gate zero, and sometimes higher, are unreliable enough to merit revising the estimate to reflect the lower level of confidence in the projection. The alternative would be a total disallowance. Consumers is correct that it is unlikely that every project will end up with a final cost at the low end of the confidence range, but, as the Staff points out, the disallowances discussed herein do not represent 100% of the cost categories for which Consumers seeks rate relief. Consumers is required to support its projections with evidence showing that they are reasonable and prudent. As is discussed at length above, the possibility that projects may potentially be implemented at the proposed cost does not constitute that kind of evidence. For some cost categories, Consumers' evidence is sufficient; for others, it is simply too light to require ratepayers to take on the burden of providing recovery. This will not prevent the utility from receiving recovery. It simply means that, if the project is, in fact, implemented, the utility may seek recovery in its next rate case and will then be in a position to provide evidence and argument that the investment was reasonable and prudent.

Specific adjustments are discussed below. All adjustments discussed herein are to the non-contingency portion of the expense, as the contingency portion is addressed above in Section III.A.1. Similar to the distribution capital expenditure discussion, the heading for each disputed generation cost projection discussed below contains the line or page on which the expense appears in Exhibit A-12, Schedule B5.2, pp. 8-9, where possible.

a. 2019 Generation Capital Expenditures

The Attorney General proposed an adjustment of $4.8 million to 2019 actual generation capital expenditures on Schedule B5.2, page 1, which Consumers agreed to, and the PFD approved. PFD, p. 103. No exceptions were filed, and the Commission adopts the adjustment.

b. 2020 Generation Capital Expenditures (Page 8)

i. Campbell Site Commons—Bottom Ash Tanks (Line 4)

Consumers projected $1.2 million in 2020 capital expenditures for a bottom ash chemical treatment system for the Campbell plant bottom ash tank system. Consumers posited that this project is necessary for maintaining compliance with National Pollutant Discharge Elimination

System permit requirements by installing a chemical treatment system which will reduce suspended solids from the discharge water. 6 Tr 1989. Consumers explained that this projected cost was based on a class 4 estimate, and class 4 estimates carry with them a low expected accuracy range of -15% to -30% and a high expected accuracy range of +20% to +50%. 6 Tr 2072-2073.

The Staff proposed that the Commission rely on the low end of the low range (-30%) to determine a disallowance and reduce the project cost by 25% (not including contingency amounts) or $298,000. 8 Tr 4759. The Staff's proposed adjustment is based on the fact that the project has only preliminary cost estimates and lacks detailed supporting documentation. Consumers countered that it has made significant progress on the project.

The ALJ recommended adoption of the Staff's adjustment, finding it reasonable "to rely on the lower end of a range of cost estimates when dealing with uncertainties, so ratepayers are not asked to pay more in advance of construction than the company actually incurs, while still providing some additional revenue to the utility than it would receive if rate recovery awaited a determination of actual costs." PFD, p. 104. The ALJ reminded Consumers that it is "required to provide all support for its case in its initial filing." PFD, p. 105; *see also*, pp. 101-102.

In exceptions, Consumers argues that each of the class level accuracy ranges has an 80% confidence interval, and that there is little chance that 100% of projects would have an actual cost at the low end of the accuracy range. 6 Tr 2073. Consumers repeats that it has made significant progress on this project and the project installation is in the bid process. 6 Tr 2074.

For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

ii. Karn Units 1 and 2 Landfill Remedial Action Plan (Line 5)

The Staff recommended a $540,000 reduction to Consumers' projected 2020 capital expense associated with a remedial action plan for the Karn Units 1 and 2 site. The Staff based the proposed adjustment on application of the low end of the confidence range for the project cost. 8 Tr 4758-4759.

The ALJ recommended adoption of the Staff's proposed reduction, finding that the Staff's approach is reasonable in light of the error ranges associated with the estimates at the various stages of project development. PFD, pp. 105-106.

In exceptions, Consumers charges that the Staff's method is not valid.

For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

iii. Ludington Upgrade and Overhaul (Line 20)

Consumers projected 2020 capital expenditures of $9.5 million ($12.7 million with contingency) to upgrade the last of six units at Ludington, Unit 3, to a new higher-efficiency design, scheduled to be completed in May 2020. 6 Tr 2019.

The Attorney General proposed a reduction of $9.5 million for this project. The Attorney General explained that, in response to discovery requests, Consumers provided no supporting cost information and was unable to provide the winning bid, which dated back to 2010. Exhibit AG-1.27; 8 Tr 3378-3379. The Attorney General argued that it was not possible to validate the accuracy of the projections for 2020. Consumers countered that a disallowance at this late stage would be unreasonable.

The ALJ recommended adoption of the Attorney General's proposed reduction, finding that Consumers failed to provide sufficient evidentiary support for its projections. PFD, p. 107. The ALJ noted that the hearings in this case took place in late July and early August, and stated:

> As an important safeguard for the process, notwithstanding that the company's plans involve the final unit of a long-term project that has successfully increased plant efficiency, it was incumbent on Consumers to provide a detailed cost estimate in response to the Attorney General's inquiry. A review of Exhibit AG-1.27 shows it did not. Indeed, with completion of the unit overhaul scheduled for May 2020, Consumers should have had available substantial cost data to share, even if it was unable to locate the original bid documents from 2010.

*Id.* (footnote omitted). The ALJ noted that Consumers bears the burden of proof and also retains the statutory ability to extend the schedule. *Id.*, n. 254.

In exceptions, Consumers argues that in discovery it provided information on the basis for this cost, which showed that the original estimate was valid. 6 Tr 2019, 2091. Consumers contends that the Commission has considered and approved the capital expenditures for this project in several previous rate cases. Consumers notes that its rebuttal was filed on July 14, 2020. Consumers urges the Commission not to disallow these costs when the project is in its final phase.

In reply, the Attorney General notes that the ALJ confirmed that the discovery response was inadequate.

For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ. The overhaul to Unit 3 was scheduled to be complete in May 2020, and the discovery response is dated June 10, 2020. Asked to provide the "basis for the $12.7 million cost estimate" for the Unit 3 upgrade (presumably completed at this point), Consumers responded that the cost estimate "reflect[s] the balance of work for the Unit 3 ($6^{th}$ and last unit) overhaul. This annual budget amount is consistent with forecast amounts from 2018." Exhibit AG-1.27. As Consumers points out, rebuttal was filed on July 14, 2020, presenting another opportunity to provide the basis for the 2020 cost estimate. While the Commission recognizes that this project is nearing its completion (and the Commission has approved capital expenditures for this project in previous rate cases), each request for the addition to rate base of a new capital expenditure amount requires evidentiary support on the record in the case in which the request is made. The Commission may not rely on the record in a previous case. Lacking a response to the Attorney General's discovery request, the description of the work associated with the $12.7 million ($9.5 million excluding contingency) appears in Consumers' direct case as follows: "All major components of the generating/pumping unit have been redesigned and will be replaced - water turbine (aka "runner"), wicket gates, generator, and stator." 6 Tr 2019. Rebuttal does not provide any additional detail. 6 Tr 2091. This is simply an insufficient basis on which to approve recovery, and as such, the Commission finds the Attorney General's proposed reduction to be reasonable.

iv. Karn Unit Separation (Line 16)

Consumers projected expenditures of $890,000 in 2020 and $9,781,000 in 2021, for costs associated with the retirement of Karn Units 1 and 2, specifically related to the separation of Units 1 and 2 from Units 3 and 4. The retirements are scheduled for May 2023 and were approved in Consumers' most recent IRP proceeding, the June 7 order (approval of a settlement agreement). 6 Tr 1996-1997.

The Attorney General argued that it would be premature to include this projection in rate base, noting that the construction work has not been bid yet, and bidding is not planned until late 2020 or early 2021. 8 Tr 3375; Exhibit AG-1.24. Consumers countered that delays may put the availability of Karn Units 3 and 4 at risk when Units 1 and 2 cease operations in 2023. 6 Tr 2085-2086.

The ALJ recommended adoption of the Attorney General's proposed reduction. PFD, pp. 109-110. The ALJ noted that Consumers' rebuttal evidence addressed issues that were not mentioned in the initial testimony and did not relate to the separation of the units. She observed that the rebuttal addressed cost items such as community transition planning and workforce development activities for 2021, which were not initially addressed and may not actually involve capital expenditures or costs of removal. Noting other cost deferrals by the company in the past, the ALJ was not persuaded that the projected amounts would be spent. PFD, p. 110.

In exceptions, Consumers contends that delay may put the availability of Karn Units 3 and 4 at risk. Consumers argues that these costs were fully supported, and, although the rebuttal testimony discussed other important initiatives that may not involve capital expenditures, the testimony was not used to expand the capital expenditure request. 6 Tr 2084-2085, 1995-1997. Consumers maintains that any failure to begin retirement activities on time may cause problems with the operation of the non-retired units.

In reply, the Attorney General argues that this expense is premature for inclusion in rate base.

For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

c. 2021 Proposed Adjustments (Page 9)

In the discussion that follows, disputed projections are again discussed with reference to line items on Schedule B5.2, p. 9, where possible. Following the lead of the ALJ, smaller projects with no corresponding line numbers are addressed last.

i. Campbell Unit 1 – Realign 4160V Switchgear (Line 1)

This $1 million test year project is to align the Campbell Unit 1 switchgear with the company's new air-quality control system startup transformer, thereby improving safety. 6 Tr 1984.

The Staff proposed a $400,000 reduction to the projected expense, and the MEC Coalition supported a complete disallowance. The Staff noted that this is a class 5 estimate with no signed project charter. Exhibit S-17.6, pp. 16-22. The Staff's estimate reduces the projected expense to the low end of the accuracy range associated with a class 5 estimate. 8 Tr 4759. The MEC Coalition argued that the company supplied little to no documentation, admitted that the project could be deferred, and intends to conduct an economic analysis before undertaking the project in any case. 8 Tr 3925-3928; Exhibits MEC-83, MEC-148.

The ALJ recommended adoption of the MEC Coalition's proposed reduction, finding that the project is preliminary and that Consumers failed to support the projected expenditure with sufficient evidence. PFD, p. 112. The ALJ recommended the MEC Coalition's total reduction, or, in the alternative, the Staff's $400,000 reduction.

In exceptions, Consumers posits that its projected cost is reasonable, and is based on a similar project that was completed in 2015 at Campbell Unit 2. 6 Tr 2076-2077. In answer to the MEC Coalition, Consumers states that its "cost estimate had evolved as the result of the multiple reviews and refinements that were a part of the Company's project identification and estimation process. 6 TR 2101. . . . As the project continues in its lifecycle toward execution, estimate refinements are common, which is just the natural progression of project planning, and are not an indication of inconsistencies." Consumers' exceptions, pp. 65-66.

In reply to Consumers, the Staff argues that the fact that a similar project was undertaken five years ago does not, alone, demonstrate that the projected cost is reasonable. The Staff notes that, by its own admission, this cost estimate is preliminary, is subject to further refinement, and is based on the review of a similar project.

In reply to Consumers, the MEC Coalition argues that the projection is simply a ballpark estimate, and the utility failed to provide reliable documentation.

For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

ii. Campbell – Regulatory Compliance (Lines 2, 7, and 8; Exhibit A-49)

Consumers' proposed 2021 capital expenditures of $6.3 million to comply with the Steam Electric Effluent Guidelines (SEEG) at the Campbell plant are summarized on Exhibit A-49, and included in Schedule B5.2, p. 9. Consumers explained that the date for compliance with the new SEEG regulations has not been set by the United States Environmental Protection Agency, but will not be later than December 31, 2023, so the company is planning for full compliance by that date. 6 Tr 1648-1651. Consumers plans to begin design, engineering, and procurement planning in 2021. *Id.*

The Staff proposed a total disallowance of this 2021 expense due to its uncertainty. The Staff noted that Consumers has not developed planning documents for the work that is supposed to occur during the test year. Consumers countered that the disallowance could put the company at risk of noncompliance with the new SEEG rules. 6 Tr 1660.

The ALJ recommended adoption of the Staff's proposed disallowance, finding that Consumers failed to establish whether and how it would spend the projected amount. The ALJ noted that, in a discovery response, Consumers acknowledged that the design would not be finalized until the second quarter of 2022, and procurement would not begin until the third quarter of 2022, both occurring long past the end of the test year. Exhibit S-17.7, p. 8; PFD, p. 115. Because the utility did not establish whether or how it would be spending money on this project in 2021, the ALJ found the alleged risk of noncompliance to not be credible. The ALJ concluded that "Consumers has the ability to raise needed capital; the test-year funding would only represent a portion of the capital investment, which is of uncertain timing and magnitude, while the utility can reasonably be expected to file another rate case before it has finalized its spending plans for 2021, with rates expected to take effect approximately 10 months after that, i.e. around January 1, 2022." PFD, p. 116.

In exceptions, Consumers explains that it must move forward with wastewater studies in 2020, and in the test year it will design, engineer, and begin procurement for the closed loop system. 6 Tr 1651. Consumers argues that any disallowance may put it at risk of noncompliance with SEEG. The company explains that it faces a compliance schedule over which it has no control. "Until that rulemaking is finalized, the Company cannot reasonably design a compliant system. Further, due to the COVID-19 pandemic, some delays have occurred in being able to access and bring contractors on-site to conduct SEEG-related testing and have further compressed an already tight compliance schedule." *Id.*, p. 68. Consumers states that it will need funds during the test year in order to meet the December 31, 2023 deadline.

The Commission adopts the findings and recommendations of the ALJ. As Consumers recognizes, final compliance may not be required until December 31, 2023, and procurement is not planned to occur until late 2022. Consumers may have filed multiple rate cases before the final compliance date. Consumers also recognizes that its own final plans are contingent on additional wastewater studies, and the results of additional data gathering and cost development. 8 Tr 4771-4773; Exhibit S-17.7. The Commission finds the Staff's proposed disallowance to be appropriate.

iii. Campbell Retirement Analysis (Lines 3 and 6)

The MEC Coalition took issue with Consumers' projected expenditures of $1.732 million for the test year for Campbell Units 1 and 2, arguing that these costs would be avoidable if Consumers retired those units in 2024. 8 Tr 3916-3917; Exhibit MEC-83; Revised Exhibit A-69. The MEC

Coalition also identified a $2,425,000 project for replacement of the secondary air heater baskets and seals at Campbell Unit 2 as being avoidable under the 2024 retirement scenario. 8 Tr 3919-3923; Exhibit A-71. The MEC Coalition noted that Consumers is required to present a retirement analysis evaluating the economics of continuing to operate Campbell Units 1 and 2 in its 2021 IRP filing, and argued that the company should refrain from making avoidable investments in these units until it receives the results of this retirement analysis. *See,* June 7 order, pp. 48, 90, and Exhibit A, pp. 4-5, ¶ 4. The MEC Coalition asserted that the energy and capacity value of the units is significantly outweighed by the fixed costs by 2024 or 2025, and these avoidable costs should not be incurred. 8 Tr 3905-3910. Consumers countered that the MEC Coalition's analysis is flawed, that the last major inspection revealed that these components require replacement, and that it is premature to decide that the analysis will favor retirement. 6 Tr 2098.

The ALJ recommended adoption of the MEC Coalition's proposed reduction. PFD, p. 120. The ALJ found that there was no dispute that Consumers is obligated to provide a retirement analysis in its next IRP filing, which is due in June of 2021. She found that there was also no dispute that Consumers could avoid the need to invest the $1.7 million in the event of the earlier retirement. The ALJ further found that the additional basket and seal replacement project is avoidable and should be disallowed, based on Consumers' failure to show that the project must be completed in the test year. PFD, p. 120. The ALJ found that "promoting such expenditures on the eve of a comprehensive retirement analysis may unnecessarily add to the burden on ratepayers," and that Consumers may not actually make the investments. *Id.* The ALJ found that the disallowed amount should be the $1.732 million undisputed avoidable expenditures shown on

Exhibit MEC-83, plus $2.425 million for the other projects, shown on Schedule B5.2, p. 9, line 3, for a total of $4.2 million. PFD, p. 121, n. 299.

In exceptions, Consumers argues that the performance of this work in 2021 will provide for continued safe operation of Unit 2 through retirement in 2031 and that economics is not the only basis for performing work. Consumers urges the Commission not to set a retirement date for Campbell Units 1 and 2 in this case, and notes that the settlement agreement in the IRP case requires a rigorous early retirement assessment to be filed in June 2021. Consumers notes that the 2031 date was also set forth in the settlement agreement in the IRP case, and argues that this work is required in order to maintain regulatory compliance. *Id.* Consumers alleges that any disallowance is premature.

In reply to Consumers, the Staff points out that, although the Staff testified that the IRP proceeding would provide the most complete retirement analysis, it did not discuss the propriety of avoidable capital expenditures, and further notes that the settlement agreement approved in the June 7 order specifically preserved the rights of parties to present a retirement analysis in cases other than IRP cases. 8 Tr 4808. The Staff urges the Commission to reject the assertion that evaluation of retirement issues is precluded until the company's next IRP case.

In reply to Consumers, the MEC Coalition argues that these avoidable costs are imprudent and unreasonable and should not be forced upon ratepayers. The MEC Coalition contends that Consumers has failed to adequately support the projections related to these investments, and notes that in its next IRP Consumers is required to examine a 2024 and 2025 retirement date. The MEC Coalition argues that it presented evidence showing that the costs of these units significantly exceed their economic value to ratepayers. 8 Tr 3906-3907. The MEC Coalition states that Consumers failed to cite to any evidence showing that the basket and seal replacement is not avoidable. The MEC Coalition further contends that the Commission is not being asked to determine a retirement date in this case, but rather is being asked to determine whether the proposed investments are reasonable and prudent. Finally, the MEC Coalition notes that the Commission has previously deferred recovery of test year investments in Karn Units 1 and 2 as avoidable costs, while requiring a future retirement analysis. *See,* March 29 order, pp. 24-25.

The Commission adopts the findings and recommendations of the ALJ. As the approved IRP settlement agreement shows, 2024 is a potential retirement year and will be included in the company's analysis. June 7 order, pp. 48, 90, and Exhibit A, pp. 4-5, ¶ 4. While this rate case does not present a record on which the Commission would evaluate retirement dates, the MEC Coalition presented convincing evidence that these investments are potentially avoidable. 8 Tr 3916-3923; Exhibit MEC-83. Like other disallowances, this does not mean that the utility is precluded from recovery of these costs if, in fact, they are incurred and are found to be reasonable and prudent in a future rate case.

iv. Campbell Unit 3 – Monitor Replacement (Line 10)

Consumers projected $1 million in capital expense for replacing the post-combustion monitors at Campbell Unit 3, to install equipment that will monitor carbon monoxide as well as oxygen. 6 Tr 1990.

The Staff recommended a reduction of $209,000 to this expense. The Staff testified that the cost estimate for this project is class 4 and it has no scoping document, indicating that the project is still under development. 8 Tr 4760. The Staff proposed an adjustment that reflects the lower end of the accuracy range associated with a class 4 estimate. The MEC Coalition also argued that this project lacks supporting documentation. 8 Tr 3926, n. 88. Consumers countered that a concept approval document will be completed in the second half of 2020. 6 Tr 2077.

The ALJ recommended adoption of the MEC Coalition's proposal for a total disallowance, finding that Consumers failed to provide supporting documentation or proof that it would actually fund the project, and concluding that the project can be deferred. PFD, p. 122.

In exceptions, Consumers contends that, on rebuttal, the company showed that its original projection was reasonable, and argues that the ALJ failed to cite any record evidence that the project is deferrable. 6 Tr 1990, 2104.

In reply to Consumers, the MEC Coalition argues that this project can be deferred beyond the test year and lacks adequate support. Exhibit MEC-85, p. 2.

For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

v. Campbell Unit 3 – Reheater Soot-blower (Line 11)

Consumers explained that it intends to add soot-blowers to the Unit 3 reheater, which will keep ash from building up to a level that has, at times, caused outages. 6 Tr 1990-1991.

The MEC Coalition proposed a $1.3 million reduction to this projected expense based on a lack of adequate evidentiary support. The MEC Coalition noted that this project is deferrable, and the company has indicated it plans to conduct an economic analysis prior to undertaking it in any case. 8 Tr 3927-3928; Exhibit MEC-83. Consumers countered that the project is in the study phase.

The ALJ recommended adoption of the MEC Coalition's proposed total disallowance, finding that this project can be deferred and lacks adequate supporting documentation. The ALJ noted Consumers' admission that an economic analysis needed to be performed, and found the project to be premature for inclusion in rate base. PFD, p. 123.

In exceptions, Consumers argues that, simply because an additional economic analysis is planned, that does not make its current projection invalid. 6 Tr 2102.

In reply to Consumers, the MEC Coalition argues that this project is premature.

For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

vi. Campbell Unit 3 – Soot-blowing Air Compressor (Line 12)

Consumers testified that it plans to evaluate, design, and implement air supply system upgrades to improve the efficiency of Campbell Unit 3, with engineering and procurement planned for 2020, and project implementation occurring in the spring of 2021 during a planned outage. 6 Tr 1991. Consumers projected expense of $1.2 million for 2021.

The Staff testified that the project has a class 4 cost estimate, but the project charter reflects significantly less expense than the company's projection in this case. 8 Tr 4762-4763. The Staff argued that the clarification provided by the company did not provide further support for the cost projection. The Staff proposed a reduction of $240,000 to the test year cost projection to reflect the lower end of the range of accuracy associated with a class 4 projection, and also argued that the cost discrepancy was never cleared up.

The ALJ recommended adoption of the Staff's proposed reduction, finding a lack of evidentiary support. PFD, p. 126.

In exceptions, Consumers states that this is a two-year project, with the engineering and material procurement to be accomplished in 2020, and implementation in the spring of 2021, and the project is currently in its initial phases. 6 Tr 1991, 2080. Consumers argues that this is no longer an economic project but instead has become a condition-based project. 6 Tr 2103.

For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

vii. Campbell Unit 3 – Mill Overhauls (Line 14)

Consumers explained that this projected $1.2 million expense for the test year, and $603,000 for 2020, is for the periodic rebuild of the coal mills for Unit 3, which experience degradation over time, resulting in reduced performance and increased reliability risk. 6 Tr 1998, 1991.

The MEC Coalition proposed a disallowance of the entire test year $1.2 million expense on grounds of lack of support. 8 Tr 3927.

The ALJ noted that this expense was not addressed on rebuttal, and recommended adoption of the MEC Coalition's proposed disallowance. PFD, p. 127.

In exceptions, Consumers states that this projection is based on recent experience, due to the fact that the company completed mill overhauls for Campbell Unit 1 in 2014, 2017, and 2019. 6 Tr 2100-2101. Consumers argues that it appropriately relied on actual experience, and that it does not typically prepare scoping documents or project charters for this type of routine project.

In reply to Consumers, the MEC Coalition argues that even "routine" projects require supporting documentation.

For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

viii. Campbell Site Commons – Dry Ash Landfill Cell (Line 15)

Consumers projected capital expense of $544,000 for 2020 and $5.2 million in 2021 for the construction and permitting of a landfill cell for dry ash disposal at the Campbell plant. Consumers explained that the on-site landfill is expected to run out of usable airspace in 2022, and that construction of this project will be completed in 2021. 6 Tr 1993.

The Attorney General proposed a disallowance of the total $5.2 million for 2021, based on information provided by Consumers in discovery indicating that the project is likely premature. The Attorney General noted that the company requires a construction permit from the Department of Environment, Great Lakes, and Energy (EGLE) and bidding on that work will not take place until the second quarter of 2021. 8 Tr 3374.

The ALJ recommended adoption of the Attorney General's proposed disallowance for the test year, finding that the Attorney General provided evidence of the uncertainty of the project in 2021. PFD, pp. 128-129.

In exceptions, Consumers states that usable air space for Ash Cell 5 will be depleted in late 2021 to early 2022, and Ash Cell 6 will need to be able to accept ash immediately when Ash Cell 5 is depleted, and the best time to do the work is spring to fall. 6 Tr 2083-2084. Consumers contends that the fact that it needs a new construction permit from EGLE will not defer the start of the work on Ash Cell 6. *Id.*

The Commission agrees with the ALJ that this project is simply too uncertain. Consumers notes that Ash Cell 6 will continue to be unusable until EGLE accepts the company's final construction report, and the company still needs a new construction permit. 6 Tr 2084. The Commission adopts the findings and recommendations of the ALJ.

ix. Karn Units 1 and 2 Site Commons – Karn Units 3 and 4 Decoupling (Line 16)

The ALJ stated that, "[f]or the reasons discussed in section 2.d above, the Attorney General's recommended adjustment of $9.78 million in non-contingency capital expense projections for this line item should be adopted." PFD, p. 129.

In exceptions, Consumers notes that there is no "section 2.d" above pertaining to this subject, and offers that this is a reference to the Karn unit separation costs. Consumers argues that the

Commission should reject this disallowance "for the same reasons the Company provided above." Consumers' exceptions, p. 78.

Because this issue also involves the separation of Karn Units 1 and 2 from Units 3 and 4, the Commission understands the ALJ to be referring to Section A.3.b. of the PFD's rate base discussion. For the reasons discussed in Sections III.A.2.a.i., III.A.3. and III.A.3.b.iv., above, the Commission adopts the findings and recommendations of the ALJ.

x. Karn Unit 3 – Cooling Tower Rebuild (Line 17)

Consumers projected $2.5 million in capital expenditure for 2021 for this project, which involves replacement of the structural timbers, stacks, and fan blades at Karn Unit 3. 6 Tr 2001.

The Staff argued the Commission should reduce the 2021 projection by $543,000. The Staff testified that the company's cost estimate is class 4 and the project is at the concept approval stage, and thus lacks a signed project charter. 8 Tr 4760. The Staff also noted that the concept approval document contains a different expense projection. Exhibit S-17.5. The Staff's proposed adjustment is based on the low end of the projected cost range for a class 4 estimate. Consumers countered that the cost estimate was based on the cost of the Karn Unit 4 cooling tower rebuild which was completed in 2020. 6 Tr 2077.

The ALJ recommended adoption of the Staff's proposed reduction, finding that the Staff's adjustment takes an appropriate middle ground. The ALJ stated that, "Consumers was given the opportunity in Exhibit S-17.5, to explain the discrepancy between its concept approval 'contingency' designation and its projection on line 17 of Schedule B5.2, page 9, and while it admitted an error in its 'concept approval' document, [it] did not explain why it reported 'contingency' on line 17 if the project cost does not include contingency." PFD, p. 130. The ALJ noted that, even with the Staff's reduction, about $1.8 million is retained in projected rate base for this project for the test year. PFD, p. 131.

In exceptions, Consumers again notes that this is a project with which the company has recent experience, and states that the projection is based on the Karn Unit 4 cooling tower rebuild which was completed in the spring of 2020 at a total cost of $15 million. 6 Tr 2077. Consumers notes that the construction and the age of the two cooling towers are identical, and this is the first year of a multi-year project. Consumers also repeats it criticism of the Staff's methodology which relies on the class stage of the project.

For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

xi. Karn Units 3 and 4 – Startup Optimization (Line 18)

Consumers testified that this projected $3.9 million 2021 expense is for procurement and installation of a startup boiler feed pump (BFP) for Karn Units 3 and 4. 6 Tr 2001.

The Staff proposed a reduction of $1.56 million to 2021 costs to reflect the lower limit of the expected accuracy range. 8 Tr 4763. The Staff noted that Consumers has a signed project charter, but it covers only the inspection of equipment, there is no detailed scoping, and the project has a class 5 estimate. The Staff's recommendation is based on the lower end of the accuracy range associated with a class 5 estimate.

The ALJ recommended adoption of the Staff's proposed reduction for 2021, based on a lack of supporting documentation and the fact that Consumers would not be performing a thorough inspection, to underlie the estimate, until 2020. PFD, pp. 131-132.

In exceptions, Consumers objects to the Staff's method, and argues that it supported the scope and cost of this project.

For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

xii. Jackson Site Commons – Boiler Feed Pump Valve (Line 24)

Consumers projected expenditures of $1.16 million for the test year to replace the automatic recirculation control valves on the three BFPs at this plant with pneumatic control valves to reduce maintenance expense, increase efficiency, and increase operational control. 6 Tr 2010.

The Staff proposed a reduction to this projected expense of $116,000. 8 Tr 4760-4761. The Staff noted that the cost projection is based on a class 3 estimate, and the Staff's recommendation is based on the low end of the associated range of accuracy. The Staff pointed out that this project did not have a signed project charter, indicating that the design scope and cost estimates are preliminary. Exhibits S-17.3, p. 4, and S-17.5, pp. 11-12.

The ALJ recommended adoption of the Staff's proposed reduction based on the Staff's analysis. PFD, p. 132.

In exceptions, Consumers again argues that the Staff's method is not valid.

For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

xiii. Hodenpyl Dam – Generator Rewind (Line 28)

Consumers projects a $1.6 million capital expenditure for the test year for a generator rewind at the Hodenpyl hydro plant because the Unit 1 stator and field pole windings are in poor condition and at risk of failure. 6 Tr 2016.

The Staff recommended a reduction of $316,000 to the 2021 projected expense for this project, arguing that it is based on a class 4 cost estimate and the project is only at the concept approval stage. 8 Tr 4761. The Staff's proposed adjustment reflects the low end of the range of accuracy associated with this project.

The ALJ recommended adoption of the Staff's proposed reduction. PFD, p. 134. She took note of Consumers' rebuttal testimony stating that planning is still continuing. She found that planning is incomplete, and noted that the Staff's adjustment still allows over $1 million for the test year for this project. PFD, p. 134; 6 Tr 2078.

In exceptions, Consumers contends that the "fact that planning continues does not invalidate the project scope or cost," and states that the change in cost was based on experience with recent generator rewinds. Consumers' exceptions, p. 80; 6 Tr 2078.

For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

xiv. Hodenpyl Dam – Spillway Hoist (Line 29)

Consumers projected a $1.6 million expenditure for 2021 to evaluate the original spillway hoist at Hodenpyl Dam for adequacy, ergonomics, and redundancy. 6 Tr 2016.

The Staff recommended a reduction of $1.325 million to this 2021 projected expense. The Staff noted that the budgeted total for the project in the company's confidential supporting documents is "significantly less than" the filed projection. 8 Tr 4761; Exhibit S-17.6, pp. 33-37. The Staff's recommendation is based on the absence of evidentiary support for the additional expense, thus the Staff recommends reducing the projection to the budgeted amount in the project scoping document. Consumers countered that the safety of the hoists is important, and a failure could lead to additional costs. 6 Tr 2078-2079.

The ALJ recommended adoption of the Staff's proposed reduction, finding that, "[a]s Staff argues, the scope of the project remains uncertain. This PFD also notes that the company is required to provide supporting documentation for its cost projections with its filing; it is not to include cost projections as placeholders to be filled in during the rebuttal phase of the proceeding. Staff's reliance on Exhibit S-17.6 is appropriate." PFD, p. 135.

In exceptions, Consumers argues that on rebuttal the company showed that this project estimate was reviewed during preparation of the company's 2021 Long Term Financial Plan, and the initial estimate rose from $1,625,000 in 2021 to $1,720,000 in 2021. 6 Tr 2078-2079. Consumers argues that this evidence reinforces the original projection by showing that it was actually too low; however, the company only requests to recover the original amount.

In reply to Consumers, the Staff argues that Consumers cannot dispute that the scope and costs of this project have changed significantly since the application was filed, and the project remains in the development phase. 6 Tr 2078-2079. The Staff argues that the company has provided no support for its assertion that the costs have actually increased.

The Commission disagrees with the ALJ and declines to adopt the Staff's proposed reduction. In its direct case, Consumers provided the following testimony:

> At Hodenpyl there is only one hoist that operates both the caterpillar spill tube gates and the head gates. The original hoist is in poor operation, it has two different reels for the different gate chain sizes required for the two different types of gates. There are potential pinch points, ergonomics concerns with the hooking and dogging of the chains. Evaluate the hoist for adequacy, ergonomics, and redundancy. This project is tied to the risk evaluation of the initiation of the emergency spillway at Hodenpyl. The spill tubes have enough capacity to pass the Inflow Design Floods at Hodenpyl but if we lose the only hoist on site, we may not be able to get a crane on site during a storm event, allowing the pond to fill and potentially initiate the emergency spillway. Therefore, the redundancy for both the head gate and caterpillar gates is necessary. The risk reduction measures from the emergency spillway study need to be incorporated into choosing the best alternate to reduce overall site risk.

6 Tr 2016. On rebuttal, in response to Mr. DeCooman's recommended disallowance, Consumers provided the following additional testimony:

> The project team is working with the Company's health and safety team to verify that two sets of movable hoists can be operated safely to protect the health and safety of our workers. If the movable hoists cannot be used safely, the project would require ten fixed hoists, at a higher cost than has been budgeted for this project. The project team is currently completing a safety review of the movable hoist option to finalize the scope of this project (on-site meeting held 3rd week in June). Final engineering is scheduled to resume this year (following results of the safety review) and to be completed in time for hoist installation next year. Upgrade of these hoists is required to ensure we can continue to operate the dam safely.

6 Tr 2087-2079. These activities are expected to ensure that the company can bring a crane on site during a storm event. In light of the testimony showing that Consumers has already begun work on this project, and considering the safety issues that are expected to be addressed by the project, the Commission finds that the proposed disallowance is not advisable and approves the company's proposed $1.6 million expenditure for 2021.

xv. Loud Dam – Training Wall (Line 30)

Consumers projected a total 2021 expenditure of $2.2 million to replace the training wall at the Loud hydro plant. Consumers testified that the projection is based on a 2018 analysis showing significant deterioration in the underwater portion of the training wall, and that a new study is required to "reassure that the new design is adequate." 6 Tr 2015.

The Staff recommended a $660,000 reduction to Consumers' projected expenditure for this project, on grounds that the project has no signed project charter but only a concept approval document with a class 4 cost estimate. The Staff's adjustment reflects the lower end of the expected accuracy range associated with this class. Exhibit S-17.6, pp. 38-42; 8 Tr 4762.

The ALJ recommended adoption of the Staff's proposed reduction, again reminding Consumers that it is required to provide adequate support for its projections with its application and not during rebuttal. PFD, p. 137.

In exceptions, Consumers contends that it provided project costs in its direct case. 6 Tr 2015. Consumers states:

> The Company included a $2,200,000 project cost to replace the training wall. 6 TR 2015. In 2018, the third-party condition assessment consultant identified that the underwater portion of the training wall was severely deteriorated and the whole wall is bowing significantly. The dive inspection observed that cracking, separation at the base from the spillway apron, and leaning of the wall indicate the concrete reinforcement may be the only resistive force providing stability of the wall system. Replacing the training wall would reduce the probability of failure of the training wall, its adjacent structures, and the overall dam operations. The use of an updated study would reassure that the new design is adequate. Design engineering shall include performing a study for the Au Sable River that includes creating the tailwater rating curve for multiple flow levels up to PMF [probably maximum flood]. *Id*. Thus, the Company did not wait until the rebuttal phase to support the project and its costs.

Consumers' exceptions, p. 83. Consumers notes that on rebuttal it showed that the FERC recently reviewed and approved the project design for construction completion by December 31, 2021. 6 Tr 2079; Exhibit A-171. Based on this approval, Consumers states that it is moving forward with its competitive solicitation for this project, and the project will be similar to the Webber Training Wall Project which is currently underway. Consumers argues that the rebuttal reaffirmed the original estimate.

The Commission disagrees with the ALJ with respect to this dam project as well. In its direct case, Consumers offered the following evidence:

> In 2018, the third-party condition assessment consultant identified that the underwater portion of the training wall was severely deteriorated and the whole wall is bowing significantly. The dive inspection observed that cracking, separation at the base from the spillway apron, and leaning of the wall indicate the concrete reinforcement may be the only resistive force providing stability of the wall system. Replacing the training wall would reduce the probability of failure of the training wall, its adjacent structures, and the overall dam operations.

6 Tr 2015. The Commission finds that the company provided sufficient evidentiary support for this important dam safety and maintenance project, and declines to adopt the Staff's proposed reduction.

xvi. Ludington Site Commons – Barrier Net (Line 35)

Consumers projected a $1.9 million capital expenditure in 2021, as part of a multiyear project, to study and improve the Ludington barrier net, with a goal of reducing fish entrainment. 6 Tr 2021-2022.

The Staff proposed a $400,000 reduction to this projected test year expense. Exhibit S-17.6, pp. 43-47. The Staff indicated that this project has only a concept approval document in support rather than a signed project charter, and recommended an adjustment to the low end of the accuracy range associated with this class 4 estimate. 8 Tr 4762.

The ALJ recommended adoption of the Staff's proposed reduction based on the project's early development stage. PFD, p. 138.

In exceptions, Consumers argues that the Staff's method is not valid.

For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

xvii. Ludington Site Commons – Reservoir Liner (Line 36)

Consumers projected capital expense of $5.6 million for the test year to replace the reservoir liner at the Ludington plant. 6 Tr 2092.

The Attorney General proposed a disallowance of the full amount. The Attorney General testified that, in response to discovery, Consumers failed to provide an engineering study or supporting data for the cost components. The Attorney General contended that the discovery response also indicated that the company is still working on the design phase of the project, that the accuracy and reasonableness of the capital expense projection could not be validated, and that the timing is uncertain. 8 Tr 3379-3380; Exhibit AG-1.28. Consumers countered that the project cost is based on an engineering report, which was provided as a confidential exhibit, that engineering is complete, and that the project is currently in the bid process. 6 Tr 2093-2094; Exhibit A-170.

The ALJ recommended adoption of the Attorney General's proposed disallowance, finding that Consumers failed to provide a credible discovery response. PFD, p. 139; Exhibit AG-1.28. She noted that the company failed to explain the basis for the engineering estimate, and found that "10-month rate cases require that the utility provide complete and accurate information on request." PFD, p. 139.

In exceptions, Consumers argues that it is necessary to install a new mastic liner over the asphalt liner, which has become brittle and subject to water intrusion. 6 Tr 2022, 2092. Consumers contends that it showed that if it does not replace the mastic liner prior to 2023, the upper six inches of the asphalt liner of the entire reservoir would need to be replaced by 2027, and this work can only be performed within certain temperature tolerances. 6 Tr 2093-2095. Consumers contends that on rebuttal it answered the Attorney General's questions and concerns, and the engineering report that was relied upon was admitted as Exhibit A-170 (filed confidentially). Consumers states that it has retained a contractor that specializes in reservoir liner replacement, and that it provided a project status on rebuttal.

In reply, the Attorney General argues that the company failed to provide supporting data for the cost components, the bid process is ongoing, and the cost information provided in the confidential report is very general and preliminary.

For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ. The Commission agrees with the ALJ that Consumers' discovery response was inadequate, and the company's direct case, though it indicates that the liner is becoming more brittle, was not very convincing with respect to the need for these expenditures in 2021. 6 Tr 2022. On rebuttal, Consumers indicates that the work should be accomplished prior to 2023. The Commission observes that this provides the company with sufficient time to both accomplish the work and to file, if it chooses, a future rate case in which the company may provide a stronger direct case. In any event, Consumers is not precluded from receiving recovery of amounts that are spent to repair or replace the reservoir liner that are shown to be reasonable and prudent.

xviii. Administrative and Other – Enterprise Project Management (Line 38)

Consumers projected 2021 capital expenditures of $2.9 million for its Enterprise Project Management Information System, described as an "analytics reporting tool . . . which will enable the company's Enterprise Project Management Office to understand performance and trends across all of its projects, obtain greater insight into cost and schedule metrics, and customer reports and portals to support the business." 6 Tr 2026.

The Staff recommended a $1.9 million reduction to this 2021 projection based on discrepancies between projected and actual expenses in 2018 and 2019. The Staff noted that Consumers failed to provide any of the standard scoping documents, including a detailed scope of work or cost information. 8 Tr 4764.

Finding the Staff testimony and analysis to be persuasive, the ALJ recommended adoption of the Staff's proposed reduction. PFD, p. 141.

In exceptions, Consumers argues that the Staff failed to provide support for this proposed disallowance that is based on the company's historical performance for 2018 and 2019.

For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

xix. Campbell Units 1 and 2 – Section 316(b) Compliance (Exhibit A-48)

Consumers projected spending $500,000 at the Campbell plant in 2021 on activities related to compliance with section 316(b) of the Clean Water Act, 33 USC 1326(b). Exhibit A-48. Consumers stated that federal rules promulgated under this section set standards for cooling water intake structures at power generation facilities. Consumers explained that, to comply with promulgated impingement and entrainment standards for the protection of fish, EGLE may later require Consumers to make intake modifications at Campbell Units 1 and 2. The company acknowledged that there is uncertainty regarding the completion of EGLE's review and what the company's compliance obligations will eventually be. 6 Tr 1645-1646. The company argued that the projected expense would position Consumers to be able to act quickly. 6 Tr 1651.

The Staff recommended a total disallowance of the test year amount due to the uncertainty in the timing and scope of work for this project. Exhibit S-17.7. The Staff noted that it is uncertain when the company will receive a determination from EGLE regarding its obligations. 8 Tr 4769. Consumers countered that EGLE may respond with its review in 2020. 6 Tr 1661.

The ALJ recommended adoption of the Staff's proposed disallowance, finding that the adjustment was well supported, and that "[i]f Consumers does spend money on some currently-undetermined study in the last half of the projected test year, and it can explain those planned expenditures in its next rate case, it would likely begin recovery as soon as January 1, 2022." PFD, p. 143.

In exceptions, Consumers notes that it provided testimony indicating that the company expects EGLE to respond soon, since it has been over two years since the April 2018 submission of the required documentation to EGLE. 6 Tr 1661. Consumers states that "if EGLE does respond at any point in 2020 or during the first half of 2021, then Consumers Energy will need the requested funds to begin compliance activities during the test year." Consumers' exceptions, p. 88. Consumers explains that:

> [T]he Company expects to receive a Best Technology Available ("BTA") determination from EGLE for compliance with Section 316(b) in 2020. The requested $500,000 in the test year will position the Company well to be able to react to the EGLE's final BTA determination. If an entrainment BTA is required, then the Company will move forward with the design and engineering of an alternate intake structure for Campbell Units 1 and 2. 6 TR 1645, 1661-1662. However, if EGLE agrees that the existing cooling water intake at Campbell is sufficient and requires the Company to then evaluate impingement, the requested test year dollars will then be spent on impingement studies on the Campbell Units 1 and 2 intakes. 6 TR 1651.

Consumers' exceptions, p. 88.

Again, this project is premature for inclusion in rate base. For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ.

xx. Smaller Projects (Exhibit MEC-83)

The MEC Coalition argued that the Commission should reject the projected expenses associated with 17 small projects, none of which individually is large enough for inclusion in Schedule B5.2. These projects are listed on Exhibit MEC-83, with a designation of the reason for the recommendation, and a reference to the discovery responses relied on by the intervenor. The MEC Coalition argued that these small projects are associated with unsupported projected costs of $6.1 million. The MEC Coalition argued that the company's designation of a project as routine does not obviate the need for supporting documentation, and that many of the projects the company characterizes as routine do not line up with the historical costs associated with that type of project. Exhibits MEC-85, MEC-86. The MEC Coalition argued that the costs of some projects vary significantly from year to year, or are only planned sporadically. Consumers countered that it does not prepare project charters for routine projects such as these. 6 Tr 2100-2104.

The ALJ recommended adoption of the MEC Coalition's proposed reduction, finding the MEC Coalition's analysis and argument persuasive, and finding that Consumers failed to provide adequate support for its cost projections for these smaller projects. PFD, pp. 144-145.

In exceptions, Consumers argues that the MEC Coalition has overstated the cost of the 17 projects, stating that, after exclusion of 5 of the 22 projects on Exhibit MEC-83 (on other grounds), the remaining 17 projects have a total cost of $4.922 million, not $6.1 million. Consumers' exceptions, pp. 89-90. Again, Consumers contends that it does not prepare charter documents or scoping documents for these types of routine projects because they are very predictable. 6 Tr 2100-2101.

In reply to Consumers, the MEC Coalition agrees with the company that the PFD overstates the test year cost of these 17 projects, and the disallowance should be $4.922 million. MEC Coalition's replies to exceptions, pp. 84-85. The MEC Coalition urges the Commission to disallow these costs because they have no supporting documentation.

For the reasons discussed in Sections III.A.2.a.i. and III.A.3., above, as well as the reasons articulated by the ALJ, the Commission adopts the findings and recommendations of the ALJ, but revises the disallowed amount to $4.922 million.

xxi. Biannual Environmental Regulatory Meetings

In the February 28, 2017 order in Case No. U-17990 (February 28 order), p. 32, the Commission approved the Staff's proposal "that Consumers meet with the Staff biannually so that the company may keep the Staff apprised of pertinent developments and changes in the regulatory compliance landscape and compliance strategies." Consumers requested that the Commission lift this requirement. 6 Tr 1662. The ALJ did not address the request. In exceptions, Consumers repeats the request, arguing that the environmental regulatory landscape has slowed considerably since the 2017 order came out, no other regulated utility is subject to this requirement, and the company is happy to meet with the Staff whenever there are pertinent developments in environmental regulations or the company's compliance strategies change. Consumers asks that these meetings occur on an as-needed basis.

The Staff filed no reply.

The Commission approves the request and finds that these meetings may take place on an as-needed basis.

4. Facilities Capital Expense

For the test year, Consumers projected approximately $65 million for its Electric Operations Support capital expenditures. *See*, Exhibit A-12, Schedule B-5.6. The company explained that these expenditures include two cost categories: asset preservation and computer and other equipment. According to Consumers, "[i]nvestment in Asset Preservation of the Company's facilities generally includes investment in new construction, remodeling of existing facilities, emergent work, lifecycle replacement of infrastructure equipment and system failures. 6 TR 1801." Consumers' initial brief, p. 142. The company proposed major asset preservation projects for facilities, which include the Lansing Service Center, Kalamazoo Service Center, Hastings

Service Center, and Circuit 501, and land acquisition for future construction of a Unified Control Center (UCC).

a. Lansing, Hastings, and Kalamazoo Service Centers

Consumers projected capital expenses of $2,746,000 and $25,567,000 for 2020 and 2021, respectively, for the replacement of the service centers in Lansing, Kalamazoo, and Hastings. The company asserted that, based on its facilities assessments, the three service centers have deteriorated to the extent that replacement is more economical that remodeling or repair. In addition, Consumers stated that, "the space requirements of the existing workforce have significantly changed, requiring open office environments, collaborative work groups, computer technology in the workplace, and the need for internet and wireless communication networks[,] all [of which] support the need for a newly constructed, rather than renovated, facility." Consumers' initial brief, p. 148. Finally, the company asserted that relocation/construction of the new service centers will improve aesthetics, customer accessibility, and energy efficiency.

In testimony, the Attorney General requested that the Commission deny Consumers' proposed expenditures for the service centers because "the projects are still in the very early stages of design and development" and construction may not occur in 2020 or 2021. 8 Tr 3383. She stated that, in discovery, the company was asked to provide the square feet of space, the number of employees housed, and the type of operations at the old and new service centers. The Attorney General stated that Consumers provided the square feet and number of employees at the old service centers, "but did not provide the same information for the new proposed service centers." *Id*., p. 3382. In addition, she contended that it may be unnecessary to conduct some operations at the new service centers because these operations may be more appropriately executed at Consumers' headquarters. In sum, the Attorney General asserted that Consumers has not demonstrated that the projects are fully and specifically developed and, therefore, she recommended that the Commission approve capital expenditures of $1,782,000 for 2021, with the remaining costs deferred to a subsequent rate case.

Consumers responded that, in Case No. U-20650, the Attorney General supported the company's proposal to replace the service centers. According to the company, "she has suddenly shifted positions, four months later, and requests disallowances related to the replacement of those same service centers, suggesting that the expenditures be delayed to year 2022." Consumers' initial brief, p. 153. Consumers asserted that it provided detailed discovery responses that specifically identified the project timelines and construction details for all three service centers.

The Attorney General disputed the company's characterization of her position in Case No. U-20650; she did not support the construction of the three service centers in that case. Rather, the Attorney General stated that, although "she performed some limited discovery on the issue, other more pressing priorities prevented her from doing enough discovery to enable her to reach a determination on the propriety of the proposed expenditures" and she did not file testimony on the issue. Attorney General's reply brief, pp. 12-13. She asserted that the additional discovery conducted in this case demonstrates that Consumers provided insufficient detail to support the capital expenditures for the three service centers.

The ALJ agreed with the Attorney General, in part. She stated that:

> A review of the detailed timelines contained in Exhibit AG-1.31, page 3, shows that none of the three service centers will be available for use in the 2021 test year. In fact, although the Kalamazoo and Hastings Service Centers are more advanced, all three of the service centers will still be under construction in 2022, at which point furnishing and commissioning will need to be completed. Thus, none of these buildings will be used and useful in the provision of utility service during the test period.

PFD, p. 148. She recommended that the Commission reject Consumers' proposed capital expenditures of $2,746,000 and $25,567,000 for 2020 and 2021, respectively.

In exceptions, Consumers objects to the ALJ's recommendation to disallow the capital expenditures for the service centers. The company states that "there is no finding by the ALJ indicating that they are unreasonable or imprudent. In fact, the PFD appears to imply that the approval of the projects would be appropriate but for the ALJ's independent determination that 'none of these buildings will be used and useful in the provision of utility service during the test period.'" Consumers' exceptions, p. 93 (quoting PFD, p. 148). Consumers asserts that the ALJ incorrectly presumes that the Commission must apply the "used and useful" test to determine whether the capital expenditures for the service centers may be included in rates. *Id*. The company argues that there is no precedence for this presumption and, in any event, "the ALJ incorrectly appears to apply a narrow and rigid interpretation of the 'used and useful' doctrine to conclude that only facilities that are immediately useful can qualify for recovery in rates. This too is without any record evidence, is incorrect, and is improper." *Id*.

In addition, Consumers asserts that no party to this case recommended a disallowance based on the "used and useful" doctrine. The company states that:

> there is no Michigan authority on the record to support the ALJ's position that a cost may not be included in rates of a regulated utility unless that cost is for an asset that is "used and useful" in the provision of utility service. This is likely because precedent in Michigan clearly states that "*the PSC is not bound to any particular method or formula* in exercising its legislative function to determine just and reasonable rates." *See Ass'n of Businesses Advocating Tariff Equity (ABATE) v Public Service Comm'n*, 208 Mich App 248, 258; 527 NW2d 533 (1994).

Consumers' exceptions, pp. 93-94 (emphasis in original).

The company explains that, in *ABATE*, it requested recovery of costs related to the construction of a nuclear power plant in Midland, Michigan, that was approximately 85%

complete but never finished because of site problems and federal regulatory complications. Consumers states that, in *ABATE*, the Commission "applied the 'prudent investor' test and allowed the Company to recover a portion of its investment made before the date that the Commission determined that the Company should have known that further investment was futile. *ABATE*, 208 Mich App at 254-256." *Id*., p. 94. The company notes that, on appeal, the appellants argued that the Commission was required to apply a "used and useful" test before it could include the costs in rates. However, Consumers asserts that the Court of Appeals rejected the appellants' arguments and affirmed the Commission's decision. The company explains that, "[i]n doing so, the court approved the Commission's use of the 'prudent investor' standard under circumstances in which the Commission deems it appropriate and wrote that '[w]hat is important is whether the result reached is just and reasonable.' *ABATE*, 208 Mich App at 266." *Id*. Moreover, Consumers contends that the Commission later recognized this broad discretion in the February 14, 2007 order in Case No. U-14672. Therefore, the company asserts that the ALJ erred in finding that the Commission is required to apply the "used and useful" standard to the capital expenditures.

Furthermore, Consumers contends that the ALJ failed to acknowledge that the Staff did not object to the expenditures and she did not discuss the supporting facts regarding the service centers' current condition and need for replacement. The company cites its testimony and exhibits supporting the proposed capital expenditures and reiterates its request for approval of the costs. *Id*., pp. 95-96.

Finally, Consumers asserts that the ALJ's recommendation is contrary to the fundamental ratemaking concept of allowance for funds used during construction (AFUDC). The company states that:

> Per long standing Commission practice and order, construction projects over six months in duration and over $50,000 are considered AFUDC eligible. In a rate

> case, the return calculated on AFUDC eligible CWIP is offset in the revenue requirement calculation by increasing net operating income with an AFUDC offset. The effect is that there is no requested rate relief for AFUDC eligible projects. Instead, the financing costs during construction for these projects are accrued and capitalized with the project to be collected over the life of the asset.

Consumers' exceptions, p. 98 (quoting 6 Tr 2271). Consumers contends that capital spending included in CWIP that is not AFUDC eligible does receive a return in the revenue requirement calculation. 6 Tr 2271. Consumers argues that the Lansing, Hastings, and Kalamazoo Service Centers are AFUDC-eligible projects with an AFUDC offset. In addition, the company notes that the ALJ acknowledged on page 189 of the PFD that the Commission has determined that CWIP should be included in rate base. Consumers contends that, "[i]f it is true that CWIP should be included in rate base, as previously upheld by the Commission, then the service center capital spending in this case, which is AFUDC-eligible CWIP with an AFUDC offset, should be included in rate base." Consumers' exceptions, p. 98. Thus, the company requests that the Commission reject the ALJ's recommendation to disallow the capital expenditures associated with the new service centers.

In response to Consumers' claim that the ALJ inappropriately interjected and applied the "used and useful" doctrine in this case, the Attorney General states that "[t]he Company cites to no authority for the premise that the ALJ cannot apply its own analysis to the evidence." Attorney General's replies to exceptions, p. 29. In addition, she disputes the company's claim that the ALJ determined "that the Commission must apply the 'used and useful' doctrine." *Id*. (emphasis in original). The Attorney General asserts that the ALJ made no such statement in the PFD.

RCG also disputes Consumers' claim that the ALJ erred in applying the "used and useful" doctrine. RCG asserts that, contrary to Consumers' contention that there is no Michigan authority to support the ALJ's recommendation, the "used and useful" doctrine is set forth in Michigan statutes, including MCL 460.557. In addition, RCG asserts that Consumers inappropriately relied on *ABATE* to support its position. RCG states that, "[w]hile that case clarifies that the Commission was not limited to utilizing only the used and useful test, the Court affirmed the Commission's utilization of a 'reasonable and prudent' investment test." RCG's replies to exceptions, pp. 5-6. RCG asserts that, in other words, the "used and useful" test is one of the factors that the Commission may consider in setting just and reasonable rates.

The Commission finds persuasive the Attorney General's argument that the service center projects are in the early stages of design and development and that construction will not be complete until 2022. Exhibit AG-1.31, p. 3. As noted by the Attorney General, Consumers failed to provide sufficient detail for the projects, such as the square feet of the new service centers or the number of employees that will be housed there. *See*, 8 Tr 3383-3384; Exhibit AG-1.31, pp. 1-3. Therefore, the Commission finds that, at this time, Consumers' proposed capital expenditures for the Lansing, Kalamazoo, and Hastings Service Centers are not adequately supported and should not be approved.

In light of the above determination, the Commission finds that it need not address Consumers' claim that the ALJ erred in applying the "used and useful" doctrine.

b. Circuit 501 Project

Consumers proposed capital expenditures of $1,570,000 for 2019, $2,805,000 for 2020, and $26,484,000 for 2021 for the Circuit 501 training center. The Staff and the Attorney General disputed the costs, asserting that the project appears to be in the early stages of development and that the company failed to provide sufficient justification for the project.

The ALJ agreed with the Staff and the Attorney General, finding that Consumers' "direct testimony supporting the project is less than one page and only provides a very generalized overview of the training center with references to vague benefits . . . ." PFD, p. 150. She recommended that the Commission disallow the 2019, 2020, and 2021 expenses for the Circuit 501 project.

There were no exceptions filed and, therefore, the Commission adopts the ALJ's findings and conclusions on this issue.

c. Unified Control Center Project

Consumers explained that its current control center has two groups: electric supply and grid management. According to the company:

> The buying and selling of electricity is monitored and controlled through the Merchant Operations Center in Jackson. The electric grid is monitored, controlled, and dispatched by multiple operational centers with two control centers: the System Control Center ("SCC") in Jackson which handles Transmission and HVD lines and the substation network of 138 kV and 46 kV systems; and the Distribution Control Center ("DCC") in Grand Rapids which handles the 46 kV substations feeding the LVD overhead and underground line system, including some of the 3-phase LVD system and the metropolitan system. The LVD overhead and underground line distribution system not covered by the DCC is dispatched from three LVD dispatch centers, one each in Grand Rapids, Saginaw, and Jackson.

6 Tr 1912-1913. Consumers proposed $1 million for 2021 to construct a modernized hardened facility, which will be designed using current industry security, resiliency, and operability, to combine the two groups and incorporate an emergency operations center function. The company asserted that customers will benefit from reduced risk during catastrophic events and there will be faster restoration times, particularly during storms and unique events. *Id.*, p. 1913.

The Attorney General objected to Consumers' proposed expenses. She stated that, "[i]n discovery, the Company was asked to provide certain basic information on the proposed project, such as the number of square feet of space for the facility, the total cost from inception to completion, and the need to replace the current facilities with a new combined center." 8 Tr 3387. The Attorney General noted that the timing of the expenditures differs between the discovery responses received from Consumers. In addition, she asserted that the location of the new facility has not been determined. Therefore, the Attorney General contended that the company failed to provide sufficient detail for the project.

Consumers responded that "the UCC is important to allow for continual operation without interruption during catastrophic weather and other events. . . . The Company is currently lagging when compared with other utilities in moving to a centralized control room. 6 TR 1927." Consumers' initial brief, p. 156. The company reiterated the arguments set forth in testimony, asserting that the Commission should reject the Attorney General's recommended disallowance.

The ALJ found "that because it is unclear how the $1 million will be spent, whether on project scoping only, or on project scoping and land acquisition, the requested expense should be disallowed in this rate case." PFD, p. 153.

In exceptions, Consumers reiterates the arguments set forth in testimony and briefing. In addition, the company states that:

> The PFD's concern regarding whether the $1 million will include only project scoping or project scoping and land acquisition is not warranted. Company witness Brenda L. Houtz indicated that the planned project timeline includes property site selection and acquisition, along with design completion and contractor and vendor selection, in the test year. 6 TR 1920. Ms. Houtz testified that "the Company is projecting $1 million to complete concept scope, the facility site requirements, and property selection and acquisition in 2021." 6 TR 1921. The Company reiterated these plans in discovery, pointing to this portion of Ms. Houtz' direct testimony and indicating that the $1 million planned for 2021 is for research and possible land purchase. See AG-1.33, pages 1 and 4. Thus, the record shows that the projected $1 million in 2021 is for the purpose of completing project scope *and* property site selection and acquisition.

Consumers' exceptions, p. 100.

In reply, the Attorney General reiterates that Consumers has not specifically defined how the funds will be used for this project and the company failed to justify the need for a UCC. She states that, "[a]lthough the Company is only requesting $1 million in this case, the Commission should not approve the recovery of any capital expenditures for this project until a compelling business case is made by the Company regarding the necessity for the entire project." Attorney General's replies to exceptions, p. 31.

The Commission agrees with the ALJ and the Attorney General that Consumers' test year capital expenditures for the UCC project should be disallowed. As noted by the Attorney General, in Consumers' discovery response, Exhibit AG-1.33, pages 3-4, witness Brenda L. Houtz stated that the estimated yearly spending plan for the UCC is: $1,000,000 for 2021; $50,000,000 for 2022; $35,000,000 for 2023; and $15,000,000 for 2024. However, in a separate discovery response, Exhibit AG-1.33, page 5, Consumers' witness Patrick C. Ennis stated that the anticipated annual cost for the UCC project is: $1,000,000 for 2021; $28,765,000 for 2022; $38,269,000 for 2023; and $32,383,000 for 2024, which differs from the cost break-down provided by Ms. Houtz. In addition, Consumers stated that the projected $1 million in capital expenditures for 2021 is for *possible* land acquisition. Exhibit AG-1.33, pp. 3-4. Moreover, the company admits that the "[l]ocation for the UCC project has not yet been determined." *Id*., p. 5. Therefore, the Commission finds that Consumers has not clearly defined how and when the capital expenditures for the UCC will be spent. As with other disallowances, Consumers remains free to seek recovery for any reasonably and prudently incurred expenditures related to the UCC project and/or to repropose these investments in future rate cases with greater detail.

5. Fleet Services Capital Expense

Consumers projected capital expenditures of $28,674,000 in 2019, $33,222,000 in 2020, and $62,749,000 in 2021 for fleet services to replace out-of-lifecycle vehicles, heavy equipment, and trailers for all departments. The company noted that its fleet services capital expense was $17.5 million for the 2018 historical year. 6 Tr 2118. Consumers stated that its "Fleet Services capital spending is projected to increase in the test year, when compared to the 2018 historical year, because the Company is proposing to move to a fleet lifecycle between five and eight years versus the current fleet lifecycle of 12 to 15 years." Consumers' initial brief, p. 157. The Staff recommended a disallowance of $39.569 million and the Attorney General requested that the Commission approve a capital expense of $21,664,000.

a. Transportation Equipment Replacement

Consumers proposed a capital expense of $31.5 million for vehicle replacement in 2020 and $32 million in 2021. The company explained that:

> nearly $26.902 million of the $31.5 million requested for Fleet capital investment in the projected test year has been allocated toward the Company's most critical Electric Operations units and $4.606 million in funding has been allocated to the purchase of trailers and heavy equipment to support the work the Company's crews are performing. 6 TR 2124. This plan was developed using the analytics provided by Utilimarc for replacing out-of-lifecycle units and comparing the outcome of the study with the Company's own internal data. 6 TR 2124. Utilimarc is an independent third-party vendor and industry leader in utility Fleet analytics that performs benchmarking, data analytics, statistical analysis, and provides real-world utility industry experience. 6 TR 2116.

Consumers' initial brief, p. 159.

According to the company, maintaining the fleet services expense at the 2018 historical amount is insufficient because dollars are used for both electric and natural gas fleet vehicles and Consumers is constantly performing "triage" for vehicles on both sides of its business. *Id*., p. 160. Consumers states that "[t]his impact, based on the previously budgeted dollar amount, has resulted in a Fleet with an average age of over 8-years-old and, in some cases 12- to 15-years-old, and has also resulted in more than 1500 units out of 7000 being used beyond their lifecycles." *Id*. The company asserted that, if it executes Utilimarc's recommended spending plan, Consumers can optimize maintenance costs. In addition, Consumers asserted that, by 2027, cost avoidance is estimated to be $14 million less for maintenance and the company can also maintain its zero impact to start-of-day operations.

The Staff requested that the Commission disallow the company's proposed increased capital expenditures for fleet services. The Staff asserted that, at the historical expense amount of $17.5 million, Consumers has been able to meet its electric business goals of on-time delivery, estimated time of restoration, customer average interruption duration index (CAIDI), SAIDI, and system average interruption frequency index (SAIFI). If the Commission finds that the fleet services expense should be increased, the Staff recommended that the Commission adopt its fleet services calculation, which begins with the $17.5 million historical amount and applies an inflation factor of 1.610% for 2020 and 2.263% for 2021. The Staff explained that "[m]aintaining the historical spending level of $17.5 million annually, plus inflation, for fleet lifecycle replacement is appropriate until the Company can demonstrate the additional spending is reasonable and prudent." Staff's initial brief, p. 77. In addition, the Staff noted that the Commission has raised concerns about the Utilimarc report, specifically with the treatment of depreciation, in Consumers' most recent natural gas rate case. *See*, September 26 order, p. 46.

The Attorney General also recommended that the Commission reject Consumers' proposed fleet services capital expenses. She disputed the validity of the Utilimarc study, asserting that "[t]he calculation that underly [sic] this analysis was . . . based on inconsistent and divergent assumptions." Attorney General's initial brief, p. 69. Moreover, the Attorney General stated that:

> The analysis performed by Ultimarc [sic] and the [company] testimony of Mr. Jones is not supported by any cost/benefit analysis that assesses whether the incremental capital investments, as proposed by the Company, are justified by a reduction in maintenance expense. As noted above, the numbers presented represent a composite average across a proxy group compiled by Ultimarc [sic]. There is no indication that this large increase in capital spending will provide the claimed economic benefit on a net present value basis.

*Id*., p. 70. The Attorney General noted that the average capital fleet services expense for 2017-2019 was $21,664,000 and, as a result, she recommended setting the base capital expenditures for Transportation Equipment at this amount.

Regarding the Staff's and the Attorney General's recommended disallowances, Consumers asserted that they fail to consider the time and expense of maintaining the company's aging fleet. Consumers' initial brief, pp. 167-168, 171-172. In response to the Attorney General, Consumers asserted that it sufficiently supported the proposed expenses and demonstrated that the company's vehicle fleet is deteriorating. According to Consumers, "the high unit availability has 'only been obtainable through increased Fleet expense as the Company performs necessary maintenance and repairs . . . on out-of-lifecycle vehicles, often on a daily and nightly basis, to ensure the availability at the next start-of-day for Operations.'" *Id*., p. 171 (quoting 6 Tr 2148). In addition, Consumers contended that there has been a significant jump in maintenance costs in recent years—specifically, a 17.5% increase from 2017 to 2018, and a 15.4% increase from 2018 to 2019—indicating that maintenance costs are trending upward and the fleet is deteriorating faster than normal. *Id*., pp. 171-172; 6 Tr 2149.

The ALJ noted that the Commission discussed a very similar proposal in Consumers' most recent natural gas rate case. Quoting page 46 of the September 26 order, she stated that the Commission found that Consumers did not make "'a convincing case that the alleged exorbitant future maintenance costs will materialize.'" PFD, p. 158. The ALJ stated that, because "this determination was made just over a year ago, and [because] Consumers relies on essentially the same evidence in this case (namely, the 2017 Utilimarc report) as it did in Case No. U-20322, this PFD finds that Consumers' proposal to almost double its spending on transportation fleet is still not sufficiently supported." *Id*., p. 159. She stated that Consumers' dismal predictions in Case

No. U-20322 have not materialized and, once again, the company has not provided a benefit/cost analysis. Therefore, the ALJ found that the Staff's proposal to use the historical expense of $17.5 million, escalated by the Staff's inflation amounts, to be reasonable and recommended Commission approval. Finally, she recommended that Consumers "provide a benefit/cost analysis in a later rate case, preferably one that evaluates various average fleet ages, not just the 5.5 years that the Utilimarc report deemed optimal." *Id*.

In exceptions, Consumers asserts that the ALJ failed to discuss the reasonableness and prudence of the company's evidence and did not acknowledge that, in this case, Consumers addressed some of the Commission's concerns from the September 26 order. The company reiterates the arguments set forth in testimony and briefing, restating that it is laborious and costly to maintain an aging fleet. Consumers argues that if the Staff's disallowance is adopted, it "will impact the Company's ability to execute on a proportionate and consistent plan to replace out-of-lifecycle units, lower maintenance cost, and provide value to customers through lower rates." Consumers' exceptions, p. 103. Finally, the company states that the ALJ failed to acknowledge that Consumers provided evidence, both historical and projected, demonstrating a continued increase in costs if the company's proposed fleet services expense is not approved.

In its replies to exceptions, the Staff disputes Consumers' claim that the Staff did not refute the company's proposal to increase maintenance spending. Rather, the Staff states, "the intent of Staff testimony was to point out that the Company has not taken all of the necessary steps to remedy the deficiencies that the Commission identified in U-20322 and [to] show that the Company's fleet services have not impacted its ability to meet reliability metrics or respond to customer requests." Staff's replies to exceptions, p. 29. The Staff reiterates that Consumers has not demonstrated that its proposed expenses are reasonable or prudent and requests that the Commission adopt the ALJ's recommendation.

The Attorney General replies that the Commission should adopt the ALJ's recommendation for the reasons set forth in the PFD and her initial brief. She states that:

> the Company has not made a convincing case that undertaking a capital spending program which greatly increases the amount of annual expenditures is economically justified. It has not proven that transportation equipment is deteriorating at a faster pace and that O&M costs are escalating significantly to support its proposed expenditures. To the contrary, the evidence shows a high unit availability rate of nearly 100%.

Attorney General's replies to exceptions, p. 32.

The Commission agrees with the ALJ and finds that the Staff's proposal to use the historical expense of $17.5 million, increased by the Staff's inflation amounts, should be approved. As noted by the ALJ, the Commission addressed a very similar issue in Case No. U-20322. In that case, Consumers provided extensive testimony on this issue, which forecasted exorbitant future maintenance costs. In the September 26 order, the Commission found that the company did not provide convincing evidence that the costs would materialize.

In this case, Consumers has, once again, presented extensive testimony, alleging that maintenance costs are increasing at an exponential rate and will continue to grow faster than normal. The company asserts that maintenance costs increased 17.5% in 2018 and 15.4% in 2019. However, Consumers admits that a simple average of maintenance costs for 2009-2019 shows that, over a ten-year period, costs increased by an average of 6.3% annually. 6 Tr 2149; Exhibit AG-1.35, p. 2. And, the company states that "increases from years 2017 to 2019 demonstrate an average annual increase of only 3.5% . . . ." 6 Tr 2149. Therefore, the Commission finds that the exorbitant future maintenance costs alleged by Consumers in Case No. U-20322 have not materialized. And, in this case, the Commission finds that Consumers has not demonstrated by a preponderance of the evidence that maintenance expenses will increase at the rapid pace claimed by the company.

Consumers also relies on a 2017 Utilimarc report to support its proposed expenditures. *See*, Exhibit A-72. As noted by the ALJ and the Staff, the Commission expressed concerns in Case No. U-20322 regarding Utilimarc's depreciation calculation. Similarly, the Commission finds that Consumers has not adequately addressed the depreciation issue in this case.

Finally, with fleet unit availability of almost 99%, the Commission agrees that Consumers is doing an excellent job maintaining that availability, and finds that the company has simply failed to show that actual harm will result from keeping current investment at the historical level, escalated with the Staff's inflation amounts. At this level, the company is able to meet its electric business goals of on-time delivery, estimated time of restoration, CAIDI, SAIDI, and SAIFI. *See*, 6 Tr 2116, 2119-2120, 2124, 2128; 8 Tr 4872-4873.

b. Low Voltage Distribution/High Voltage Distribution Expansion

Consumers projected $27.320 million for the test year to support Electric Operations LVD/HVD workforce expansion. The company explained that it is hiring skilled LVD workers and building the HVD workforce to execute its Electric Distribution and Infrastructure Improvement Plan. Consumers stated that:

> The expansion efforts of Electric Operations without funding for additional vehicles and equipment to support that expanded workforce would further negatively impact Electric Operations' ability to complete the work and deliver value to the Company's customers as the Company will not have enough units to support the personnel and work associated with the proposed expansion.

Consumers' initial brief, p. 163. According to the company, it has considered placing retired fleet units back in service and the possibility of renting units from third-party vendors to accommodate the expanded workforce and additional work anticipated. However, Consumers asserted that the costs to place retired units back in service or to rent units are more expensive and unpredictable compared to acquiring new units.

The Staff recommended that the Commission disallow $12.247 million for additional vehicles associated with workforce expansion. The Staff stated that it:

> must better understand (1) the need for the additional Company workforce and (2) the Company's ability to obtain the projected additional workforce. Although Staff does not doubt that the Company will need additional workforce to support the future planned LVD and HVD work in the field, the testimony that discusses the additional workforce was limited and fails to show critical pieces of information such as the shortfall if the employees are not added, the impact of retiring employees, and the future trend on the use of contractor crews to help support the field work.

8 Tr 4874-4875. The Staff explained that Consumers has not sufficiently supported the number of employees it plans to hire. According to the Staff, "[t]he [discovery] response provided in [Exhibit S-26.2, p. 2] further demonstrates that the Company has only added 12 apprentice employees as of April 21, 2020, more than one quarter of the way through 2020–an evident shortfall of over 50% from the anticipated number of apprentices." *Id*., p. 4875. As a result, the Staff argued that Consumers has not adequately justified the need to acquire over $24 million in fleet for employees who have not yet been hired. Moreover, the Staff noted that, if the company hires apprentices, there will be a period of on-the-job training when an apprentice would be limited in job functions and accompanied by a more senior employee. The Staff asserted that additional fleet would not be needed for the 2021 test year because the apprentices would likely use the same fleet as the senior employees to carry out the work. *Id*., p. 4876.

The Attorney General noted that Consumers claimed that the new equipment purchases will support 234 new employees in Electric Operations. However, she asserted that the company's witnesses provided conflicting evidence regarding the number of prospective new employees and that the number appears to be 143. Attorney General's initial brief, p. 72 (citing 8 Tr 3394-3395).

Therefore, she contended that it is reasonable to reduce Consumers' proposed capital expenditures for transportation vehicles for new employees by 50%.

The ALJ agreed with the Staff and the Attorney General. She stated that, "given the progress in hiring apprentices as of April 2020, it appears unlikely that all of the additional vehicles Consumers proposes will be necessary for purchase in the test year." PFD, p. 161. In addition, the ALJ found the Staff's testimony persuasive that new apprentices will be sharing fleet with senior employees during the test year. Therefore, she recommended that the Commission adopt the Staff's and Attorney General's proposed disallowance of $12.247 million.

In exceptions, Consumers asserts that the Staff "speculated regarding a shortfall in hiring apprentices based on the number of hires made as of April 21, 2020, which was not informative of the 2021 test year, in which the Company plans to hire 96 apprentices." Consumers' exceptions, p. 106. The company also disputes that there is a discrepancy in the number of new employees that will be hired in the test year, as claimed by the Attorney General. According to Consumers:

> The difference between the number of employees lies in the fact that the Fleet plan was established to fulfill the needs of Operations to hire additional Company employees to meet the demands of the planned workload to be performed by Company employees including a portion of that workload currently being performed by contractors. 6 TR 2154. Mr. Detterman's testimony and exhibit, however, identified the total Company and contractor resource requirements and net change there–irrespective of any shift from contractor resources to Company employees.

*Id*., pp. 106-107. Consumers contends that it provided sufficient evidence to support its proposed LVD/HVD workforce expansion expenditures and requests that the Commission reject the ALJ's recommendation.

The Staff disagrees that its analysis of the company's hiring shortfall is speculative. Rather, the Staff asserts that its position is supported by actual hiring data: "The Company confirmed through discovery a shortfall of greater than 50% in actual hired apprentices from January to April

2020 compared to the Company's projections for that same period." Staff's replies to exceptions, p. 30. The Staff argues that if Consumers is permitted to purchase fleet equipment before employees are hired, it places an unreasonable cost burden on customers.

In reply to Consumers, the Attorney General states that "[t]he Company excepts for [sic] the PFD's recommendation, however none of its arguments refute the PFD's recommendations. For the reasons provided in the PFD and the Attorney General's Initial Brief, the Commission should remove $12.2 million from this category of expenditures." Attorney General's replies to exceptions, p. 33 (footnote omitted).

The Commission finds that Consumers has not sufficiently supported the proposed test year expense of $27.320 million for LVD/HVD workforce expansion. As noted by the Staff, the company has only hired 12 apprentices as of April 21, 2020. 8 Tr 4875. And, although Consumers claims that it plans to hire 96 apprentices in the test year, page 2 of Exhibit S-26.2 shows that, in the last five years, the company has never hired more than 78 apprentices in one year. Therefore, the Commission finds that, at this time, Consumers has not demonstrated an ability to hire the number of planned employees. The Commission finds that the ALJ's recommendation is well reasoned and should be adopted.

c. Telematics

Consumers proposed $1.202 million and $6.0 million for 2020 and 2021, respectively, for Telematics. The company explained that, "Telematics is a combination of hardware and software used for monitoring vehicles, equipment, and trailers by using Global Positioning System ("GPS"), the various control modules within the units, and the vehicles' onboard diagnostics." 6 Tr 2137. According to Consumers, it currently has two Telematics systems, Trackstar and Fleetilla, that provide basic functionality, but are no longer supported. The company proposed replacing the two systems with Utilimarc's Telematics because it "(i) specialize[s] in utility fleets; and (ii) can integrate and overlay the vehicle information within the various platforms of Electric Operations to combine multiple data points which will deliver value added services to our customers." 6 Tr 2139. The Staff did not dispute Consumers' projected expenses.

The Attorney General requested that the Commission disallow the company's proposed Telematics expenses for 2020 and 2021. She stated that "[i]n response to discovery, the Company also provided the calculation of the capital and O&M savings of nearly $11.5 million for both the electric and gas businesses from implementation of the Telematics system. Assuming the cost savings materialize, the new system seems to be a reasonable capital investment that pays for itself very quickly." 8 Tr 3396. As a result, the Attorney General contended that there is no need to increase rates to pay for the initial system.

Consumers responded that the Attorney General's "argument overlooks that the Company requires the funds to make the Telematics purchases and that the benefits are not all realized up front, but are, rather, realized over time." Consumers' initial brief, p. 173. The company asserted that the system will be installed in 2021 and that the benefit of annual savings will occur in future years.

The ALJ stated that "[a]s Consumers points out, neither Staff nor the Attorney General question the benefits of Telematics, but because the system will not be fully installed until part way through the test year, the savings that will offset the costs will not accrue immediately." PFD, p. 162. She noted that the Attorney General did not directly respond to Consumers' rebuttal regarding the timing of expected cost savings. Therefore, the ALJ found Consumers' request for the Telematics expenses to be reasonable and should be approved.

In exceptions, the Attorney General objects to the ALJ's recommendation. She asserts that, "'Assuming the cost savings materialize, the new system seems to [sic] a reasonable capital investment that pays for itself.' The offsetting of the cost of the system with the savings is key. The Attorney General believes it is reasonable for the Company to recover the funding through savings and therefore recommends that the Commission adopt her recommendations." Attorney General's exceptions, p. 16 (quoting her initial brief, p. 73) (footnote omitted).

In reply, Consumers states that "[t]he PFD correctly noted that neither Staff nor the Attorney General questioned the benefits of the Company's proposed capital expenditure for its Telematics system." Consumers' replies to exceptions, p. 28. The company contends that the Attorney General now takes exception and contradicts her previous support for Telematics, asserting that the system is reasonable only if it pays for itself. Consumers argues that her exception is inconsistent with the evidence in this case, is without merit, and should be rejected by the Commission.

The Commission finds that the ALJ's recommendation is well reasoned and should be adopted. Consumers explains that its two Telematics systems, Trackstar and Fleetilla, are no longer supported. The company asserts that Utilimarc's Telematics system is an ideal replacement because Utilimarc specializes in utility fleets and its Telematics system provides benefits that flow to customers. 6 Tr 2139. The Commission agrees with the ALJ that the company will not immediately recoup the cost benefits; rather, they will accrue over time. Therefore, the Commission finds that Consumers' proposed capital expenditures for Telematics should be approved.

6. Information Technology

Consumers proposed IT capital expenditures of $56.4 million for 2019, $55.6 million for 2020, and $73.8 million for 2021. In discovery, the Attorney General requested that Consumers provide actual 2019 capital expense for IT. The 2019 actual IT expense provided by the company was $4,011,000 less than the projected amount for 2019. Consumers and the Attorney General agreed that this amount should be excluded.

a. Operations Commercial Theft Project

The Staff recommended that the Commission disallow test year capital expenditures for Operations Commercial Theft because the expenses were not sufficiently supported. According to the Staff, in 2018 and 2019, Consumers spent $1.43 million in capital expenditures on Theft Analytics Phase 2 to detect cases of residential customer theft. The Staff asserted that, in the immediate case, the company is proposing to recover an additional $311,842 in capital expenditures and $131,784 in O&M expense to enable the theft and fraud teams to identify cases of commercial theft.

However, the Staff stated that, "[i]n an audit request in the Company's gas rate case, Case No. U-20650, Staff asked why the current theft analytics that were developed for the residential theft detection could not be applied to commercial meter data. The Company responded that the funding is needed to develop high-value algorithms that are specific to commercial theft." 8 Tr 4782. Accordingly, through discovery in Case No. U-20650, the Staff requested additional information from Consumers regarding the algorithms that are specific to cases of commercial theft. The Staff noted that, in response, the company contended that additional meter event data was needed but did not provide the requested information regarding algorithms. The Staff stated that the same audit request was presented to Consumers in this case and that the company has not updated its answer or provided the requested information regarding the algorithms. Furthermore, the Staff contended that Consumers was unable to estimate the number of cases of commercial theft it expects to locate. 8 Tr 4783.

In response, Consumers stated that:

> Commercial meters are more complex than residential meters and the usage patterns differ. Because commercial meters do not have the same technology as residential Advanced Metering Infrastructure ("AMI") meters, this data currently does not exist within the Company's data infrastructure. The project will gather and analyze this unique data, build and test new algorithms, and finally develop and generate reports that will provide high confidence instances of commercial theft. It would be improper for the Company to estimate the number of commercial theft cases it expects to see without having the required data in a viewable format.

3 Tr 241.

The ALJ found that, although Consumers explained that it cannot gather necessary data using AMI meter information and attempted to demonstrate the benefits of the project, the company did not quantify the benefits. In addition, she stated that Consumers "does not fully explain why a separate mechanism is required to detect commercial theft, rather than simply using or adapting the existing algorithm for residential theft." PFD, p. 164. Therefore, she recommended that the Commission adopt the Staff's recommended disallowance until the company can provide more detailed information in a subsequent rate case.

In exceptions, Consumers objects to the ALJ's determination, asserting that it "provided the benefits of the project and explained why the residential theft solution is not sufficient to effectively identify commercial theft." Consumers' exceptions, p. 109. The company also asserts that it cannot specifically quantify the expected number of commercial theft cases until the required data is available in a viewable format. Consumers contends that this project will make that data available. Nevertheless, the company notes that from 2009 to 2019, it experienced an average of 51 commercial thefts per year.

In reply, the Staff asserts that it is not recommending that Consumers be prohibited from making an investment in the Operations Commercial Theft project. Rather, the Staff explains that it objects to the company's request to recover the cost of the project from ratepayers. Additionally, the Staff notes that, in exceptions, Consumers reiterates that the project will gather and analyze data using algorithms that are unique and different from residential theft. However, the Staff states that "the Company has *not* distinguished the specific algorithms needed for the commercial theft detection at this time, nor at any time previously in this case." Staff's replies to exceptions, p. 18 (emphasis in original). Thus, the Staff requests that the Commission adopt the ALJ's recommendation.

The Commission finds that the ALJ's recommendation is well reasoned and should be adopted. Although Consumers asserts that commercial meters do not have the same technology as residential AMI meters, the company failed to sufficiently explain why, once the appropriate data is collected from commercial meters, the algorithm for residential theft cannot be adapted to detect commercial theft. Therefore, the Commission finds that Consumers' proposed capital expenditures and O&M expenses for the Operations Commercial Theft Project should be disallowed until the company can quantify the benefits and provide more detailed information regarding the specific algorithm needed for commercial theft detection.

b. Centralized Demand Response Management Project

Consumers stated that its Centralized DR Management project is dependent on its DR Management Assessment project and that both projects are needed in the 2021 test year. According to Consumers, "[t]hese projects are meant to address several key gaps related to the management and control of the Company's DR programs." Consumers' initial brief, p. 177. Consumers proposed test year O&M expenses of $305,700 for the DR Management Assessment project. The company also proposed test year capital expenditures of $1,293,000 and test year O&M expenses of $127,000 for the Centralized DR Management project.

The Staff did not dispute the costs for the DR Management Assessment project, but recommended that the capital and O&M costs for the Centralized DR Management project be disallowed, which includes capital expenditures of $480,481 for 2019 and $1,293,000 for 2021, and O&M expenses of $123,000 for the test year. The Staff stated:

> There is insufficient evidence to support the "Centralized Demand Response Management" project because the assessment project, which will determine the scope of the project, has not yet been completed. The Company plans to complete the assessment project and then immediately proceed with the project itself. As Staff witness Fromm testified, Staff's concerns are compounded by the fact that the current DRMS [demand response management system] cost ratepayers nearly $15 million in capital expenditures and was only implemented four years ago. (Exhibit S-18.3, p 9.) In this case, the Company is requesting additional capital and O&M expenditures to potentially replace this recent, significant investment. Ms. Fromm recommends that the Company should share the results of the assessment and future plans with Staff before any additional rate recovery is granted.

Staff's initial brief, pp. 64-65. The Staff asserted that, to be clear, it is not recommending that the company delay the Centralized DR Management project; rather, the Staff's recommendation is related to potential rate recovery only. In addition, the Staff contended "that any costs incurred and recovered through rates should be reconciled and included in the next Integrated Resource Pan [sic] (IRP) as a cost to the DR resources either project supports." *Id.*, p. 65.

In response, Consumers reiterated that the two projects are interconnected and needed for 2021. The company explained that the Centralized DR Management project includes an updated, or wholly new DR system, which will allow decision making to be brought under the control of a central operator. Consumers asserted that this operator will more efficiently implement the appropriate blend of DR resources because the full suite of available DR resources will be visible as well as load on the system. In addition, the company stated that if the variety of current DR systems are consolidated, it would "improve response time, reduce waste associated with current inefficiencies and reduce the likelihood of errors or miscommunication between the operators calling on the DR resource and those implementing the DR event." 6 Tr 1573. Consumers contended that, if the expenses associated with the Centralized DR Management project are not approved, the company will need to hire additional employees, which will be more expensive than the cost of the project. Finally, the company objected to the Staff's recommendation to include DR assessment and management costs in the IRP, arguing that it will cause regulatory lag of several years.

The ALJ noted that Consumers mistakenly included $480,481 in capital expenditures for 2019 and that the company agrees this expense should be excluded. Regarding the company's remaining expenses for the Centralized DR Management project, the ALJ recommended that the Commission adopt the Staff's disallowance, namely $1,293,000 in capital costs for 2021 and $123,000 in test year O&M expense. She stated that:

> As the company admits, the project will not be developed until the Centralized Demand Response Assessment is complete, thus, the scope of the DR management project is unknown at this point. The ALJ also agrees with Staff's concern about the fate of DRMS, for which ratepayers covered the $15 million cost only four year ago. Finally, the ALJ agrees that costs of DR assessment and DR management (when approved) should be reviewed and included as DR costs in the IRP.

PFD, pp. 166-167. She noted that the Staff provided clarification in its initial brief that it is not suggesting that Consumers may only obtain recovery through the IRP process; rather, the Staff is recommending that the costs be included in Consumers' next IRP case to accurately represent the costs of the DR resources that the company supports.

In exceptions, Consumers requests that the Commission reject the ALJ's recommendation, asserting that the "Staff's position would unreasonably impede the Company's reliance on DR resources and the implementation of the Company's IRP approved in Case No. U-20165."

Consumers' exceptions, p. 110. In addition, the company argues that the proposed capital and O&M expenses are reasonable and prudent even if the specific solution to gaps related to the management and control of the company's DR programs is unknown at this time. According to Consumers, it "does not mean that there is a deficiency in the Company's proposal for these projects. The Company has determined that a Centralized DR Management system is necessary and requires a timely solution in 2021. 6 TR 1571-1572." *Id*., p. 111. Finally, Consumers reiterates that the Staff's recommendation to include and reconcile the costs in the company's next IRP case should be rejected. Consumers states that its next IRP is scheduled to be filed in 2021 and would not be completed until 2022 and, therefore, would unreasonably delay approval and installation of a viable and needed solution for several years.

In response to the company's claim that the Centralized DR Management project is necessary because Consumers plans to significantly rely on DR as part of its capacity resource portfolio and that an increase in DR resources was approved in its IRP, the Staff states that "these costs should be included in the IRP to represent costs associated with the resources they support, however, the Company failed to explain why this was not done in the Company's previously approved IRP." Staff's replies to exceptions, pp. 19-20. In addition, the Staff asserts that Consumers has not addressed the Staff's and the ALJ's concerns regarding the $15 million investment it previously made in DRMS.

The Commission finds that the ALJ's recommendation is well reasoned and should be adopted. As noted by the ALJ and the Staff, the Centralized DR Assessment project, which will determine the scope of the Centralized DR Management project, has not yet been completed. 6 Tr 1552-1553; 8 Tr 4784. Therefore, the Commission finds that Consumers' proposed test year capital expenditures of $1,293,000 and test year O&M expense of $123,000 for the Centralized

DR Management project should be disallowed. In addition, Consumers failed to explain why it is necessary to replace the $15 million DRMS, which was implemented just four years ago, with the Centralized DR Management project. Accordingly, the Commission agrees with the Staff that the company should execute the Centralized DR Assessment project and share the results and its future plans with the Staff. Finally, the Commission finds that the cost of the Centralized DR Assessment project should be included in Consumers' next IRP for evaluation by the Commission and assigned to the DR resources the company supports.

c. Replace and Re-badge Project

In its application, Consumers projected capital expenditures of $347,105 for 2020 and $346,525 for the test year, as well as $33,000 in O&M expenses for the Replace and Re-badge project. This project is an IT security program and involves the replacement of existing card readers in Consumers' buildings with Human Interface Device Multiclass readers, as well as issuing new, more secure badges to employees and contractors. The Staff recommended disallowing the entire capital expenditure amount for 2020 and $69,305 for 2021 because, in response to an audit question, Consumers stated that the project has been reprioritized and will not begin until 2021. In rebuttal, the company agreed with the Staff's proposed disallowance for 2020.

However, Consumers objected to the Staff's proposed disallowance for the test year because it was based on a rough order of magnitude (ROM) adjustment recommended by the Staff. The ALJ stated that "[a]s discussed below concerning other adjustments based on ROM, the ALJ finds that Staff's approach is reasonable and recommends the $69,305 capital expense adjustment to the replace and rebadge project to be reasonable." PFD, pp. 167-168 (footnote omitted).

In exceptions, Consumers requests that the Commission reject the ALJ's recommendation.

The company states that, "[a]s discussed below in these Exceptions, disallowing $69,305 [in] capital from 2021 for the Replace and Re-badge Project because it is based upon a ROM estimate imposes a shortfall in the funding required to deliver the scope and expected outcomes of this project." Consumers' exceptions, p. 113.

In reply, the Staff states that "[t]he ALJ has recommended a 20% disallowance of the test year spend on Staff's recommendation, due to the projection being based on a rough order of magnitude (ROM) estimate. The Company disagrees with Staff's recommendation to disallow 20% of capital spend for ROM estimate projects on the whole, which is addressed later." Staff's replies to exceptions, p. 21 (internal citation omitted).

The Commission finds that the ALJ's recommendation is well reasoned and should be adopted. Based on the Commission's determination below regarding ROM estimates, the Commission finds that the Staff's proposed disallowance of $69,305 in capital expense for the Replace and Rebadge project should be approved.

d. Asset Refresh Program – Operational Technology Support Project

The Staff proposed increasing Consumers' Asset Refresh Program (ARP) Operational Technology Support project expenses by $385,979 for 2018, $156,261 for 2019, $144,168 for 2020, and $202,497 for 2021. The company agreed, explaining that:

> the recommended increases for the ARP – Operational Technology Support Project more appropriately reflect the Company's allocation related to the electric business. These increases were not part of the Company's initial filing in this case as Staff's recommendation to remove such costs from the Company's natural gas rate case, Case No. U-20650, was made after the Company's initial application was filed for this electric rate case, Case No. U-20697. 6 TR 2559.

Consumers' initial brief, p. 180.

The ALJ found that this issue appears to be settled and that the proposed capital expense should be included in rate base. PFD, p. 168.

There were no exceptions filed and, therefore, the Commission adopts the ALJ's findings and conclusions on this issue.

e. North American Electric Reliability Corporation Critical Infrastructure Protection Version 5 Project

In Consumers' most recent natural gas rate case, the Staff recommended that the Commission disallow $105,149 in 2019 for spending associated with the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) Version 5, which is a set of requirements that apply to the security of the electric system. The Staff recommended that the $105,149 be added to rate base in this case. Consumers agreed and stated that the amount was included in the company's initial filing in this case. In response, the Staff requested that the Commission disregard its original adjustment for the project.

The ALJ found that this issue appears to be settled and that there should be no adjustment for the NERC-CIP Version 5 project.

There were no exceptions filed and, therefore, the Commission adopts the ALJ's findings and conclusions on this issue.

f. Application Currency and Enhancement Projects

Consumers projected test year capital expenditures of $17,320 and test year O&M expenses of $19,436 for the Application Currency and Enhancement projects. The company explained that the expenses are necessary "to keep applications current for security and reliability, to make enhancements to existing software, and to address requests generated by changing business requirements." 6 Tr 2515.

The Staff noted that, in a discovery response, Consumers stated that:

> For Enhancements, the decisions on which software applications are to receive the stated changes/improvements are made on a monthly basis. Requests for enhancement funding are governed by a cross-functional board comprised of

> representatives from each business area. The board meets monthly to evaluate and prioritize the requested changes/improvements based on value through hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk.

Exhibit S-18.3, p. 10. The Staff determined that the cost projection for the Application Currency project, which was planned for 2020, should have been completed mid-2019. However, after reviewing Consumers' discovery response, the Staff concluded that planning would not be completed by the 2021 test year. The Staff explained that, "[b]ased on the Company's discovery answer, neither the cost projection for 2020 nor 2021 would include the planned work for the enhancements portion of the project" because Consumers' application was filed in February 2020, before planning could be completed. Staff's initial brief, p. 54. Moreover, the Staff asserted that the projects are not sufficiently defined. Therefore, the Staff recommended that the Commission disallow $2,145,217 of capital expenditures for 2020, $2,047,086 in capital expenditures for 2021, and $1,247,029 in O&M expenses for both Application Currency and Enhancement projects.

In response, Consumers contended that the Staff did not recommend disallowances for this program in the company's previous two rate cases. Additionally, Consumers stated that, although it does not know which specific software applications require enhancement, generalized "funding enables the Company to respond to emergent needs for system changes and ideas that bring value to the Company's customers that were not necessarily identified at the time the rate filing was prepared." 6 Tr 2567. Consumers asserted that, even though the enhancements are not identified prior to the rate case filing, it does not mean that they are not auditable. The Staff disagreed, arguing that the company's proposed costs are akin to contingency costs. Staff's initial brief, p. 56.

The ALJ agreed with the Staff and stated that "the amounts that the company has included for these projects are placeholders for software application updates or enhancements that will be determined at some point in the future; they are indeed unauditable." PFD, p. 171. In addition, if the project does not proceed as planned, she found that Consumers may need to recover from ratepayers expenditures that are not reasonable or prudent. Therefore, she recommended that the Commission adopt the Staff's proposed disallowance. The ALJ noted that the ROM adjustment for this program is discussed below.

Consumers excepts to the ALJ's recommendation, disputing the Staff's assessment of the projects. The company states that "while Staff asked through audit about the timing of decisions regarding which software applications would receive the changes/improvements, it did not request the specific list of software applications. Mr. Tolonen testified that the Company does in fact know which software applications are planned to be upgraded as part of the Application Currency portion of the projects. 6 TR 2564." Consumers' exceptions, pp. 113-114. Consumers asserts that it presented a table in testimony that provided an extensive list of the software applications to be upgraded, by project, in the test year.

In addition, the company contends that Exhibit A-188 contains an Enhancement Summary Report, which provides "a detailed summary of Consumers' enhancements queue of work in all stages, from submitted through closed requests. 6 TR 2566." *Id*., p. 114. Furthermore, Consumers objects to the ALJ's determination that Enhancements are placeholders for unknown work:

> Exhibit A-188 (JDT-9) was derived from an internal Company report that is updated weekly and is used to track and manage incoming requests, in-flight work, and completed enhancements. 6 TR 2568. Exhibit A-188 (JDT-9) fully demonstrated that the Company has a significant known backlog of incoming enhancement requests, as indicated by those with a demand ticket status of Submitted, Screening, or Qualified. This does not mean that all requests in the backlog will move forward; however, the backlog demonstrates the high level of demand for smaller technology efforts. Although it is not possible for the Company to state all enhancement work at the time of filing its case because of the dynamic

> nature of this short-cycle, demand-based work, cost projections for enhancements are based on the known backlog of requests and historical spend.

*Id*., p. 115 (internal citation omitted). Finally, Consumers disputes that Enhancement work cannot be audited. The company asserts that it individually tracks each enhancement using an internal demand ticket, which follows the enhancement request from inception through completion. Consumers states that it "is directly linked to internal project management and financial systems for enhancement status and financial spend oversight, enabling auditing at the individual enhancement level." *Id*.

In response to Consumers' claim that the Staff did not request the specific list of software applications, the Staff states that:

> Despite the Company's audit response which states that application upgrades are assessed annually, beginning mid-year and enhancements are decided on a monthly basis, the Company provided a list of projects planned for upgrade in the test year for application currency in its rebuttal testimony. (6 TR 256[4]-2566.) While this is reiterated in the Company's exceptions, what is not addressed are the concerns Staff brought up in its initial brief. The Company provided a list of projects, yet did not provide the costs associated with each of these projects.

Staff's replies to exceptions, p. 22. The Staff also notes that audit response U20697-SA-CE-049 states that, mid-year, the company develops estimates for the next year's financial plan. However, the Staff asserts that neither the audit response nor Consumers' rebuttal testimony addresses how the company developed a cost estimate for 2021 in the first quarter of 2020 when the application for this case was being created. In conclusion, the Staff reiterates that the investments cannot be audited because "the work for these areas is decided on a monthly basis, and the costs the Company is asking for approval of in this case represent future, projected costs." *Id*., p. 23.

The Commission finds that the ALJ's recommendation is well reasoned and should be adopted. Although Consumers provided a list of applications that may receive enhancements in the test year, the company did not sufficiently define which specific software applications will be upgraded and failed to include the costs. *See*, 6 Tr 2564-2566. In addition, the Staff questioned the accuracy of Consumers' 2021 Application Currency and Enhancement project cost estimate. The Staff pointed out that the projected estimate was provided in the company's February 2020 application in this case; however, the company was unable to explain how it acquired an accurate cost estimate in February when it is normally developed mid-year. The Commission agrees. Furthermore, because Consumers does not identify the enhancements prior to the rate case filing, the Commission agrees with the ALJ and the Staff that the costs are not auditable. 6 Tr 2567-2568; Staff's initial brief, p. 55. Therefore, the Commission finds that the Staff's proposed disallowance should be approved.

g. Dashboard/Website Redesign/Mobile Application

According to the Attorney General, in direct testimony, Consumers requested test year capital expenditures of $2,528,027 and test year O&M expense of $164,670 for Dashboard Redesign. In addition, she asserted that the company requested test year capital expenditures of $3,184,331 and O&M expenses of $434,445 for Website Redesign. The Attorney General contended that, in total, the two projects would require approximately $5.7 million in capital expenditures and $600,000 of O&M expense in 2021.

In response, Consumers stated that it "no longer anticipates test year costs for the Dashboard Redesign and Web Redesign projects identified in Table 4 of [the company's] direct testimony. In their place, the Company anticipates test year costs for a Customer Self-Service Mobile Application project." Exhibit AG-1.37, p. 1. Consumers projected test year capital expenditures of $5,712,358 and O&M expense of $599,115 for the Customer Self-Service Mobile Application (Mobile App). 6 Tr 2570.

The Attorney General responded that:

> The new project, named Mobile Application, will cost approximately $10 million and appears to be at the very early concept stage. The key project deadlines provided in the discovery response show an investment planning stage to be completed by January 1, 2021, a plan and definition phase for the project in the spring of 2021, a project execution phase sometime in 2021 to 2022, and a project go-live date in the first quarter of 2022.
>
> This information, plus a description of what the new application could accomplish was provide [sic] on June 18, 2020, six days before filing of Staff and intervenors testimony in this case. The discovery response included a couple of attachments on forecasted cost data and a general industry survey purporting to show that 30% of the Company's customers and particularly young people prefer to use their cell phone to access information from the Company's website.
>
> Aside from the short notice and the inability to adequately evaluate this change in direction, the project is at an early stage of development that even calling it a conceptual project may be a misnomer. The justification offered by the Company for this new project needs to be more fully vetted with insufficient time to perform that task in this rate case.

8 Tr 3400. Accordingly, the Attorney General recommended that the company's proposed expenses be disallowed.

The Staff agreed with the Attorney General. In addition, the Staff asserted that implementation of the Mobile App project is not expected until 2022, and Consumers failed to address costs that fall outside of the test year. The Staff stated that, "[w]hile the Company further tries to justify this project in its rebuttal testimony by testifying to the importance and benefits of a mobile app, it does not address the AGs [Attorney General's] concern that the Company would like to invest approximately $10 million on a project that, by its own data, would be utilized by 30% of its customers. (8 TR 3401.)" Staff's initial brief, p. 68. The Staff recommended that the Commission disallow the capital expenditures and O&M expenses for the Dashboard Redesign, Website Redesign, and the Mobile App project because the company failed to provide sufficient support.

The ALJ agreed with the Staff and the Attorney General regarding the capital expenditures and O&M expenses for the Mobile App, finding that:

> The project was presented far too late in the proceeding for Staff and intervenors to evaluate or assess the reasonableness and prudency of the Mobile Application; the company failed to justify the $10 million cost of the project when only 30% of the company's customers are expected to utilize the app and, based on the company's testimony and exhibits, the application will not be used and useful until sometime after the test year.

PFD, pp. 173-174. Therefore, she recommended that the Commission disallow $2,528,027 in capital expenditures for 2021 and $164,670 in O&M expense in the projected test year for the Dashboard Redesign project. She also recommended a test year $3,184,331 disallowance in capital expenditures and a $434,445 disallowance in O&M expense for the Website Redesign Project.

In exceptions, Consumers reiterates the arguments set forth in testimony and briefing regarding the benefits of the Mobile App project. The company asserts that it provided the parties notice, through discovery, of its intention to use the originally projected funding for the Dashboard and Website Redesign projects to fund the Mobile App project. Consumers contends that its discovery response, set forth in Exhibit AG-1.37, "included significant details related to the project, including the reasons for selecting the project, the expected benefits, and the project timeline." Consumers' exceptions, p. 117.

The company objects to the ALJ's determination that the project will not be used and useful in the test year. Consumers asserts that the Commission must only decide if the expenses are just and reasonable, citing *ABATE* and pages 27-28 of the May 27, 1977 order in Case No. U-5108 in support. However, the company states that "[t]o the extent the Commission is concerned with implementation timing, the evidence in this case shows that, because the Company selected a third-party vendor to provide a ready-made product that the Company can customize for its needs, the Company anticipates rolling out the base version of the Mobile App in the summer of 2021." Consumers' exceptions, p. 118. Consumers contends that Commission approval of the Mobile App project is important so that the company can meet customers' growing reliance on mobile devices and increased demand for enhanced digital engagement.

On pages 18-19 of her exceptions, the Attorney General requests that the Commission disallow forecasted O&M expense of $600,000 for the Dashboard and Website Redesign projects.

In its replies to exceptions, the Staff agrees with the ALJ that Consumers presented the project too late in the proceeding, leaving the Staff and intervenors very little time to review a complete change in project scope. Furthermore, the Staff notes that:

> in its exceptions the Company states that this change in scope represents a cost reduction in the test year of $220,000. (Consumers' Exceptions, p 116.) As both the AG and Staff point out, this reduction in the test year pales in comparison to the $10 million total project spend, which occurs beyond the test year. The assertion that ratepayers would be paying less in the test year is not a convincing argument, when the Company would be paying more in future years for this project—in which it has changed course.

Staff's replies to exceptions, p. 24. Finally, the Staff asserts that the company's call center and Direct Payment Office are broadly available for customer payment and, without a full evaluation, it is unclear whether a wide range of customers would use the Mobile App for payment.

In her replies to exceptions, the Attorney General reiterates that the capital expenses for the cancelled projects should be disallowed and that the Commission should reject the proposed Mobile App project. She states that "the project is at an early stage of development and it needs to be more fully vetted." Attorney General's replies to exceptions, p. 34.

In its replies to exceptions, RCG reiterates the arguments set forth above regarding *ABATE* and the "used and useful" doctrine. RCG's replies to exceptions, pp. 4-5.

The Commission finds that the ALJ's recommendation is well reasoned and should be adopted. Consumers presented the Mobile App project in its discovery response and rebuttal testimony, too late in the proceeding for the Staff and intervenors to conduct a full evaluation of the company's proposal and associated costs. *See*, Section III.A.2.a.i., above. And, as noted by the Attorney General, the total cost of the Mobile App project is not limited to the test year capital expenditures of $5,712,358 and test year O&M expense of $599,115; rather, the total cost of the project is $10 million, which extends beyond the test year. 6 Tr 2570; 8 Tr 3400; Exhibit AG-1.37. Moreover, Consumers admits that only 30% of its surveyed customers indicated that they would use a mobile application, instead of calling the company, to resolve an issue. Exhibit AG-1.37, p. 1. Therefore, the Commission finds that the ALJ's recommended disallowances should be approved.

h. Bill Design and Delivery Transformation, Move In/Move Out, On Bill Financing, and Move In/Move Out 3.0

Consumers proposed test year capital expenditures of $9,114,701 and O&M expenses of $1,568,428 for IT projects that support Customer Experience Design work. 3 Tr 193-194. Although two of the six projects were not disputed, the Attorney General objected to the timing of four of the projects.

The Attorney General claimed that, in discovery, Consumers was asked to identify the current phase of each of the projects, the total capital expenditures from inception to completion, the projects' cost estimate details, and other pertinent information to assess the reasonableness, timing, and certainty of the projects. She stated that:

> The Company disclosed that the four projects are still in the investment planning stage to discover the business requirements and possible technology options. In other words, like the projects discussed above, the Company is still trying to determine what it needs and how it will accomplish its undefined requirements. These projects are again at a very conceptual and preliminary stage of development.

> The forecasted capital expenditures do not belong in rate base for the project [sic] test year. The timeline provided in the discovery response is not credible given that the Company has not yet defined its requirements and does not know what technology options it needs to implement.

8 Tr 3404-3405. Therefore, the Attorney General recommended that the Commission disallow test year capital expenditures of $9,114,000 and test year O&M expense of $1.3 million.

Consumers disputed the Attorney General's contention that the projects are at "a very conceptual and preliminary stage of development." 3 Tr 258 (quoting 8 Tr 3404). The company argues that the projects are sufficiently developed and that it has executed the necessary planning activities to ensure that the projects are prudent. Consumers states that:

> Work performed in this phase includes identifying high-level business requirements, determining whether the functionality needed is already present in the Company's IT environment, exploring alternatives, identifying performance and security requirements, working with software vendors and cloud solution providers to demonstrate the effectiveness and security of their products and services, and developing the business case with project costs and benefits to confirm whether a proposed project should be approved for development and implementation.

3 Tr 258. The company contends that these projects are on hold awaiting cost approval in this case "before further planning and implementation activities, which will require the projected funding, are completed." *Id*.

The ALJ recommended that the Commission reject the Attorney General's proposed disallowance. Although she found it "somewhat concerning that the company lacks sufficient confidence in two of its programs to move forward until funding is approved in this rate case, and the ALJ agrees that the timeline for all four of the projects is ambitious, Consumers nevertheless provided sufficient support to show that the projects are in progress and will be completed in the test year." PFD, p. 176.

In exceptions, the Attorney General reiterates that these projects are still in the preliminary planning phase and, despite the company's claims that it has already performed some work, she argues that these projects are not appropriately included in rate base. The Attorney General states that:

> In a somewhat contradictory manner, the PFD chastises the Company for its lack of sufficient confidence in its programs to move forward until funding is approved and points out that the timeline for all four of the projects is ambitious, which the Attorney General noted in her brief. Nonetheless, the PFD concludes that the Company provided sufficient support to show the projects are in progress and will be completed in the test year. As discussed above, no such showing has been made.

Attorney General's exceptions, p. 18 (footnote omitted). She requests that the Commission adopt her proposed disallowance.

In reply, Consumers again objects to the Attorney General's contention that these projects are in the preliminary planning stage and that the projected expenses should be disallowed. The company states that it "has already performed the necessary planning activities in each of these projects to ensure the Company is making a prudent investment, and the projects are currently awaiting cost approval in this case to fund the additional planning and implementation activities." Consumers' replies to exceptions, pp. 29-30. Consumers requests that the Commission reject the Attorney General's proposed disallowance.

Although the Commission shares the ALJ's concern about the ambitious timelines for these projects, the Commission finds that the ALJ's recommendation is well reasoned and should be adopted. Consumers demonstrated that it has performed necessary planning activities for these projects: for the Bill Redesign and Delivery Transformation project, a request for proposals has been submitted to select a vendor for the project; for the two Move In/Move Out projects, the project scope has been developed and design work has been identified; and, for the On-bill Financing project, significant study and design work has been initiated. 3 Tr 259. And, as noted by the ALJ, the company sufficiently demonstrated that the projects are progressing and will be completed within the test year. Exhibit AG-1.39. Thus, the Commission declines to adopt the Attorney General's proposed disallowance.

i. Rough Order of Magnitude Adjustments

In this case, Consumers included a number of IT projects with costs based on ROM estimates. The company explained that IT investment forecasts begin with a ROM estimate that includes a process similar to that provided by the Project Management Institute (PMI) in its Project Management Body of Knowledge, where actual project costs may be in the range of -25% to +75% of the ROM estimate. Consumers stated that "ROM estimates are typically determined by technology and subject matter experts inside and outside the Company in comparison to similar historical projects. From that point, investment forecasting depends on the method used to deliver the intended solution." 6 Tr 2483. The company contended that it has used ROM estimates for IT cost projection in its previous two rate cases.

The Staff objected to Consumers' ROM estimates, recommending that the Commission reduce the projected costs by 20% to reflect the lower bound of the projects' estimated cost range. The Staff explained that:

> ROM cost estimates can have actual project costs in the range of -25% to +75%, whereas definitive estimates that are derived as the projects become more defined, have a range of -5% to +10%. Staff believes it is inappropriate to recover project expenditures that are based on a ROM estimate and may have costs as much as 25% lower than what has been projected. When a company files its application based on a projected test year, these capital expenditures, if unadjusted by the Commission, are used to set rates that go into effect at the beginning of that projected test year. Once set, the Commission cannot go back and retroactively adjust these rates, should they turn out to be too high. This means that the ratepayers have the potential to overpay for their services. Because the Company has chosen to file its case based on a projected test year, and these projects have cost projections based off a ROM estimate, Staff finds it inappropriate to allow full recovery of these projects. Instead, Staff recommends the Commission adjust these costs by 20% to reflect the lower bound of a definitive cost estimate, which is -5% as opposed to -25%. Similar to Staff's position on contingency, Staff believes it is inappropriate for the Company to earn a return of and on costs that may not occur,

> and foresees the Company returning at a later date to recover expenditures in excess of the amounts Staff has adjusted them by, if and when they occur and can be proven to be spent prudently.

8 Tr 4787-4788.

Responding to Consumers' claim that it has used ROM estimates for projected IT expenses in its previous two rate cases without objection, the Staff asserted that its position in prior cases is irrelevant to the immediate case. The Staff contended that it attempts to be consistent, however it reserves the right to use independent judgment in each case because it may discover new and different information through the audit and discovery process. The Staff stated that, "[i]n this case, Staff has identified several proposed projects with forecasted costs that could be as much as 25% higher than actual costs. This is simply not precise enough for ratemaking purposes." Staff's initial brief, p. 51. The Staff asserted that, if Consumers finds it too burdensome to propose rates using reasonably precise projections, then the company should file its case using an historical test year.

In response, Consumers reiterated that PMI, which bases its information on industry-wide data, states that actual project costs typically fall within the range of -25% to +75% of the ROM estimate. Therefore, the company asserts that, "[u]sing the midpoint of this industry range, it is statistically more likely that the projects with ROM estimates included in this case will collectively have actual costs +25% of ROM, or $12.4 million more than the amount of test year capital requested by the Company in this case." 6 Tr 2561. However, Consumers contended that it is not seeking to include the extra 25%, or $12.4 million, in rates and similarly there should not be a 20% disallowance for these projects. If the Staff's proposed 20% disallowance is adopted, the company argued that it will experience a "shortfall in funding required to deliver the scope and expected outcomes of those projects." *Id*. As a result, Consumers stated that it would have to perform additional analysis for each project, which would require additional investment planning time and an increased budget.

The ALJ agreed with the Staff that each rate case requires independent judgement and that the Staff's acceptance of ROM estimates in a previous rate case is not dispositive in this case. She stated that:

> As was the case with generation capital expense, the ALJ agrees with Staff that ROM estimates that are of such a wide range are simply too imprecise for ratemaking purposes, when the company has the option of including only projects that have definitive cost estimates ranging from -5% to +10%. Actual, reasonable and prudent costs for these projects are recoverable in a future rate case.

PFD, pp. 178-179. Therefore, the ALJ recommended that the Commission adopt the Staff's proposed $14,785,329 disallowance.

In exceptions, Consumers asserts that the "Staff's testimony proposing a 20% reduction did not provide any basis to conclude that it would better project the Company's costs on these projects." Consumers' exceptions, p. 120. Consumers argues that, if the Commission adopts the Staff's disallowance "after allowing the Company recovery based on the same method in previous cases, it would impose a new and significantly compounded constraint for the Company, particularly when combined with the PFD's recommendation to disallow Investment Planning O&M expense (discussed below)." *Id*. Consumers argues that its proposed capital expenditures that were based on ROM projections were fully supported by the record and are reasonable.

In reply, the Staff notes that Consumers reiterates the arguments set forth in testimony and briefing, to which the Staff has already responded. The Staff states that:

> these costs should not be approved as-filed simply because it is more likely the actual costs will fall on the higher end of the estimate bounds. (Staff's Initial Brief, pp 50- 51.) Furthermore, while a ROM estimate and other industry practices that come from the Project Management Institute may be reasonable for the Company's internal use, it is not appropriate when expecting recovery from ratepayers.

Staff's replies to exceptions, p. 25. In response to Consumers' claim that it will experience a shortfall if the Staff's disallowance is adopted, the Staff argues that the company may ask for additional recovery at a later date.

The Attorney General objects to Consumers' use of ROM estimates "because the range it provides is a general industry standard and does not necessarily reflect the Company's situation. In addition, [if it is used] at the early conceptual phase, the likelihood of inaccuracy may be even larger." Attorney General's replies to exceptions, p. 36. She expresses concern that Consumers has included very rough estimates in rate base and "seeks to recover a return and depreciation expense on forecasted investments that may not materialize." *Id*. Thus, she requests that the Commission adopt the ALJ's recommendation to disallow the expenses.

The Commission finds that the ALJ's recommendation is well reasoned and should be adopted. Because Michigan utilities are permitted to rely on fully projected test year costs and revenues, which already introduces a measure of uncertainty, the Commission finds it unreasonable to include ROM estimates with such a wide range of project costs. The Commission agrees with the Staff and the ALJ that these estimates are too imprecise for ratemaking purposes and may be burdensome for ratepayers. If Consumers reasonably and prudently incurs costs for these projects, the company may request recovery in a future rate case.

7. Demand Response Capital Expenditures

Consumers proposed DR capital expenditures of $3.7 million for business DR and $32.1 million for residential DR, for a total of $36.9 million from 2019 through 2021, and $3.2 million two residential DR pilots.

The Attorney General disputed the company's proposed capital expenditures, asserting that Consumers has increased DR costs and decreased capacity savings. She stated:

> Although the Attorney General supported the DR program in Case No. U-20165 based on the Company's forecasts and representations as to what the program could achieve and the benefits it would provide customers, the level of benefits appears to be in doubt based on the information presented in this rate case. On a combined basis, between capital spending and O&M expense, the Company is now forecasting total spending on the DR program of $111.0 million for the three years 2019 to 2021. In comparison, the Company had forecasted total spending of $75.5 million in the IRP. Therefore, the Company will be spending 47% more to achieve a lower volume of DR capacity reduction. As stated earlier, the Company now plans to achieve between 27% to 53% fewer MW capacity reductions during the three-year period. This is a disastrous outcome for customers.

8 Tr 3408. The Attorney General recommended a $3.2 million disallowance for the pilot DR programs.

The Staff did not object to Consumers' proposed capital expenditures. Although the Staff disputed one of the company's residential behavior DR programs, as discussed below, the Staff generally supported Consumers' proposed DR pilot projects. However, the Staff recommended that, for future pilot design and reporting, the projects should include: (1) key questions the pilots aim to answer, key metrics for demand savings, and the expected outcome after the designated timeframe of the proposed pilot; (2) detailed work plans with metrics and key success measures at the onset of the proposed pilot; (3) an interim impact evaluation that is conducted after the first year of the pilot if the DR pilot is expected to last more than a year; (4) consultation with the Staff throughout the pilot; (5) cost reconciliations for the specific electric vehicle (EV)-related DR pilot that take place in its DR reconciliation filings; and (6) reporting for these programs that takes place with all other DR reporting as part of the 45-day reports, DR Annual Report, and the IRP Annual Report, along with regular Staff and stakeholder engagement, and that these programs be reconciled as part of the existing DR framework. 8 Tr 4833-4836.

With the exception of the additional reporting, Consumers agreed with the Staff's recommendations. The company stated that, "given the differing reporting timeframes of the

45-Day Report and the IRP Report, the Company does not believe that those reports should include DR pilot reporting because of the potential for confusion surrounding the pilot programs." Consumers' initial brief, p. 197.

The ALJ found that the Attorney General "did not dispute the reasonableness of the proposed pilots, and Staff supported the program. Thus, the Attorney General's proposed disallowance is rejected." PFD, p. 180. She agreed with Consumers that, because of the consultation and collaboration that is required, it is sufficient to include DR pilot program updates in the DR Annual Report only.

The Attorney General excepts, asserting that the ALJ's recommendation "is inconsistent with the standards for approving expenditures. Consumers has the burden of proving a cost is reasonable and prudent and Mr. Coppola certainly called into question the reasonableness and prudence of expenditures incurred in the entire DR program." Attorney General's exceptions, p. 19. She reiterates the arguments set forth in testimony and briefing, claiming that the company will be spending 47% more than what was forecasted in its IRP to achieve a lower volume of DR capacity reduction, which is unreasonable. The Attorney General requests that the Commission adopt her proposed disallowance and recommends that the company reevaluate the DR program.

In reply, Consumers asserts that the Attorney General's request is based on her contention that the capacity reductions forecasted in the company's IRP "did not materialize" and that the "level of benefits appears to be in doubt." Consumers' replies to exceptions, p. 32 (quoting Attorney General's exceptions, pp. 20-21). The company states that the Commission should reject the Attorney General's recommendation because her conclusion that Consumers has not achieved its targeted DR capacity reductions is incorrect. Consumers explains that, in reaching her conclusion, the Attorney General only reviewed a subset of DR programs that the company provided in a discovery response, which did not include the MWs of DR programs associated with the interruptive service provision (Rate GI), the energy intensive program (Rate EIP), or other DR programs that support its DR projections in the IRP. And, in response to the Attorney General's recommendation that Consumers evaluate "the reasonableness and prudence of the DR Program, the Company already participates in an annual reconciliation of DR programs as part of the three-phase regulatory framework for DR established in Case No. U-18369." *Id*., p. 32.

The Commission adopts the ALJ's findings and conclusions. Although the Attorney General disputes the level of benefits Consumers' DR pilot programs provide to customers, the Commission agrees with the company that her conclusion is based upon a review of a subset of DR programs, which is not representative of the company's full DR program. Therefore, the Attorney General's claim that Consumers will be spending more to achieve the forecasted capacity reductions is not verified and the Commission declines to adopt her disallowance. The Commission finds that the ALJ's recommendation that Consumers include DR pilot program updates in the DR Annual Report only is reasonable and should be adopted.

8. Customer Experience Capital Expenditures

Consumers proposed Customer Experience capital expenditures of $9.92 million for the bridge period and $3.068 million for the test year. According to the company, Customer Experience:

> is comprised of three areas that collectively define the customers' experience when interacting with the Company: (i) Customer Analytics and Outreach, which involves using data analysis to understand, communicate with, and engage with customers in a meaningful way; (ii) Customer Interactions, which involves connecting with customers in their preferred channel (phone, text, and email) and enhancing the Company's digital offerings in response to customer feedback that they prefer self-serving through digital channels; and (iii) Billing and Payment, which involves providing customers timely and accurate bills and consistent payment options.

Consumers' initial brief, p. 297. The company asserted that the purpose of the Customer Experience program is to accelerate and simplify customer interactions so that customers are encouraged to choose Consumers' clean energy products in the future.

Consumers explained that the Customer Analytics and Outreach segment includes customer research, data and analytics, customer experience design, and operational communications. Consumers stated that it "is performing several projects in this area to improve the Company's ability to understand, serve, and communicate with customers." *Id*., p. 298. Then, according to the company, the Customer Interactions segment of the project uses the research, analytics, and customer experience design work executed in Customer Analytics and Outreach to interact with customers in the way they choose. Consumers stated that "[t]he Customer Interactions work includes five main focus areas: (i) Digital Customer Experience; (ii) Customer Contact Center; (iii) Business Customer Care; (iv) Field Payment Channels and Claims; and (v) Credit and Assistance." *Id*. Finally, the company explained that the Billing and Payment segment uses customer feedback to ensure that payment processes are uniform and simple and that customer bills are timely, accurate, and easy to understand.

The Staff requested that the Commission disallow $4.92 million in capital expenses and $266,296 in O&M expenses for Customer Relationship Management (CRM), which is a technology platform for managing all relationships and interactions with customers. The Staff asserted that Consumers did not sufficiently support the expenses.

> Though the Company's supplied cost/benefit analysis shows benefits from existing programs that deliver incremental participation in areas like Demand Response, the Company failed to provide the expected growth in the effected programs when asked to do so in response to Staff's audit. (Exhibit S-18.3, p 16.) The Company only stated that it expects to see growth but cannot quantify it until the project is underway. This is concerning to Staff. If this project relies on future benefits that cannot be quantified until after spending has begun, it does not seem appropriate to burden ratepayers with the risk.

Staff's initial brief, pp. 69-70. The Staff also expressed concern that the CRM program is voluntary and does not directly impact the quality of customer service.

For the Advanced Analytics Hub (AAH), the Staff recommended that the Commission disallow $1,949,996 in capital expenditures and $44,625 in O&M expense. The Staff explained that "[t]his project is intended to measure the impact of communications, outreach and engagement on utility products and services to have the ability to predict the next best service to offer a customer based on their past engagement." *Id*., p. 72. The Staff contended that Consumers failed to provide material evidence demonstrating the effectiveness of the program. The Staff stated that:

> While the Company can quantify expected benefits in the amount of $775,000/year for this project in the form of reduced customer acquisitions costs, avoided costs and operational efficiencies achieved through the project, it cannot provide whether or not the expected reduction in future spending will exceed the total expected project spend. Not until the project is actualized. (Exhibit S-18.3 p 21.) Staff does not believe the approval of an investment of an elective nature that *may* end up providing a net benefit to customers is appropriate.

*Id*., pp. 72-73 (emphasis in original).

Consumers disagreed, stating that the CRM and AAH programs "are necessary to support the Company's efforts to offer the right customer experience, to the right customers, in the right channel, at the right time." Consumers' initial brief, p. 299. Consumers contended that "[t]he CRM technology platform will assist the Company in managing all relationships and interactions with customers, connecting customer care, account management, customer activation, and customer acquisition for the Company's product and service offerings." *Id*., p. 301. The company averred that the CRM platform will reduce excessive communications to customers, provide comprehensive information to customers about their accounts, integrate with Consumers supply chain product, and identify and maintain campaigns for various customer segments across all channels. *Id*., pp. 301-302. Regarding the AAH project, Consumers asserted that it would increase insight into customer information to optimize enrollment in EWR, DR, and renewable energy programs and will improve the operational efficiencies of these voluntary customer programs. Moreover, the company claimed that better customer analytics through the AAH, along with improved communication through the CRM, are imperative to the company's IRP because the programs will help increase customer enrollments in EWR, DR, and renewable energy programs. 3 Tr 171-172.

In response, the Staff questioned "why these costs were not included in the Company's IRP as costs to the resources they are supposed to support. There is no requirement that this investment, nor the CRM, should be pushed through to rates simply because the Company doesn't believe it can achieve its IRP goals without it." Staff's initial brief, p. 73. The Staff argued that the company failed to show, by a preponderance of evidence, that the CRM and AAH program costs are reasonable and prudent.

The ALJ agreed with the Staff that the capital expenditures and O&M expenses for the CRM program and the AAH project should be excluded. She stated that:

> As Staff points out, these programs are elective; the majority of the benefits that the company lists are aspirational at best, and it is unclear whether the one quantified benefit, the reduction in customer acquisition costs, avoided costs, and operational efficiencies, Consumers did not provide the sort of detailed benefit cost analysis required to support such a program. The ALJ also agrees that the costs of the AAH project and a portion of the costs of the CRM program are to support the company's efforts to expand DR and EWR program participation. As such, these costs should be assigned to these programs in Consumers' next IRP, if the company intends to pursue these projects.

PFD, pp. 184-185.

Responding to the ALJ's determination that the CRM and AAH are elective, the company contends that her characterization minimizes the substantial benefits of the programs. In addition, Consumers states that "[t]he AAH and CRM capabilities and projected cost savings are complimentary, not overlapping. . . . The projected costs savings for these projects are unique and are not double counted." Consumers' exceptions, p. 123. Consumers also disputes the ALJ's recommendation that the costs for these projects be included in the company's IP before Consumers is allowed to pursue the projects. The company argues that "the IRP should not be viewed to inflexibly require a utility to identify in the IRP proceeding each project which the utility will use to support meeting its IRP targets, particularly considering that IRPs are only statutorily required to be filed every five years." *Id*., p. 124.

In reply to Consumers' claim that the ALJ's recommendation minimizes the concrete and substantial benefits of the CRM and AAH projects, the Staff reiterates that "the benefits are not concrete, and the claim that they are substantial has not been backed by record evidence." Staff's replies to exceptions, p. 27. The Staff argues that the only benefit the company could quantify was a reduced customer acquisition cost of $775,000 per year. However, the Staff asserts that it is unclear whether there is overlap in the quantified benefit between the two projects. And, in response to Consumers' claim that these investments should be recovered in this case, rather than included in its next IRP, the Staff states that, "[i]f these programs are in fact necessary to achieve the IRP goals, they should be associated with the resources they support in order for the model to work properly to inform the resource mix." *Id*., p. 28. The Staff requests that the Commission adopt the ALJ's recommendation because these projects are a substantial investment that has not been proven to be prudent or useful.

IT capital and O&M spending, including hardware and software to support customer billing and service, system operations, and upgrades, has been challenging for the Commission to review for reasonableness and prudence. Consequently, the Commission has directed some Michigan utilities to develop an IT plan to describe system needs and strategic goals. The Commission acknowledges that Consumers is voluntarily developing an IT plan to strategically and holistically assess IT needs, solutions, risk management, security, and decision-making approaches to support the company's customer, business, and operational functions; the Commission appreciates the company's efforts to be proactive in addressing these issues.

Nevertheless, the Commission has concerns regarding the benefits of the CRM and AAH programs in this case. As noted by the Staff, Consumers' benefit/cost analysis for the CRM program failed to show the expected growth in enrollments for programs like DR. The company admits that it cannot quantify the growth until the CRM program is underway. Exhibit S-18.3, p. 16. Although Consumers could quantify one benefit of the AAH project, the Commission finds that the company did not demonstrate that the expected reduction in future spending will exceed the total expected project cost. In addition, the Commission agrees with the Staff that it is unclear whether there is overlap in the quantified benefit between the two projects. Therefore, the Commission finds that the capital expenditures and O&M expenses for the CRM and AAH programs should be disallowed.

However, the Commission directs Consumers to include in its IT plan more detail regarding the CRM and AAH programs including, but not limited to, a benefit/cost analysis for the programs; the IT and software needed to optimize customer service and enrollment in programs such as EWR, DR, and renewable energy; and quantification of the expected growth in effected programs as a result of the projects. Consumers' comprehensive IT plan, coupled with the detailed information requested above, will assist the Commission in reviewing the company's future capital and O&M investments in IT.

In addition, as noted by the ALJ, the costs of the AAH project and a portion of the costs of the CRM program support the company's efforts to expand DR and EWR program participation.

Therefore, the Commission adopts the ALJ's recommendation that these costs should be assigned to these programs in Consumers' next IRP, if the company intends to pursue these projects.

Next, the Attorney General objected to Consumers' proposed costs for work scheduling, a service tracker, and a streetlight application. She stated that "the three projects are still in the investment planning stage to discover the business requirements and possible technology options. In other words, the Company is still trying to determine what it needs and how it will accomplish its undefined requirements." 8 Tr 3403. Thus, the Attorney General recommended that the Commission disallow test year capital expenditures of $1,020,000 for online work scheduling, $2,040,000 for the service tracker, and $1,020,000 for the streetlight application.

Consumers responded that these projects provide benefits such as permitting customers to schedule work online without having to call for an appointment, allowing customers to track the status of work orders, and offering a more convenient way to report streetlight outages. The company stated that it "has engaged in significant planning and design for the Online Communication and Service Enhancement projects, and it is incorrect for the Attorney General to contend that the projects are 'very conceptual and preliminary.' Other than claiming the projects are still conceptual, Mr. Coppola did not provide reasons that the projects should not be completed." Consumers' initial brief, p. 202 (quoting 8 Tr 3403). Consumers requested that the Commission approve the projected capital expenditures to allow the company to finalize and complete the projects.

The ALJ found that, "although the Attorney General's position may have some merit, without more (for example a history of projects being proposed, funded, and then either cancelled or delayed) the Attorney General's position relies solely on Mr. Coppola's opinion that the company's timeline is unrealistic. This is insufficient to adopt the disallowance she proposes." PFD, p. 187 (footnote omitted).

The Attorney General excepts, requesting that the Commission reject the ALJ's recommendation. She states:

> First, there is no explanation provided in the PFD for why the history of other projects matters to a determination of whether these projects are ripe for inclusion in this rate case. Second, Mr. Coppola did refer to the dashboard redesign in this case as a situation where funds were sought for one purpose and now the Company wants to have them approved for another purpose. Third, the proper inquiry is whether the Company has supported its proposed expenditures including the likelihood that the expenditure will be incurred during the projected test year.

Attorney General's exceptions, p. 23 (footnote omitted). The Attorney General reiterates that Consumers' timeline for the work scheduling, service tracker, and streetlight application capital expenditures set forth in its discovery response is not credible because the company has yet to define the requirements and has not identified technology options.

In its replies to exceptions, Consumers asserts that the Attorney General improperly characterizes the projects as undefined and unsupported. The company reiterates the information set forth in testimony and briefing, stating that it "has completed significant analysis, customer studies, and concept design work for these projects." Consumers' replies to exceptions, p. 33. Consumers also asserts that it has consulted with experts to create an accurate estimate for the projects.

The Commission finds that the ALJ's recommendation is well reasoned and should be adopted. The Commission finds that Consumers has performed substantial analysis, studies, and design work for these projects. For work scheduling, the company contends that the "project has already produced prototypes and use cases have been developed for short cycle and emergency situations." 3 Tr 256. For the service tracker, Consumers states that "the project has gone through the routine process for business case development and work has been performed to craft a high-level architecture solution and basic screen flows. Application diagrams and communication diagrams have been generated, as well as process flows." *Id*., p. 257. And, regarding the streetlight application, Consumers asserts that it "has worked with an IT Vendor to complete a Design Thinking workshop which identified key areas of focus for scope which led to an estimate. The vendor has implemented similar solutions, providing confidence in their estimate. The Company utilized Subject Matter Experts to determine internal costs and technical dependencies." *Id*. Consumers provided the total cost for each project and completion timelines in Exhibit AG-1.38. Therefore, the Commission finds that the company provided sufficient support for the three projects and declines to adopt the Attorney General's recommended disallowance.

9. Corporate Services Capital Expense

Consumers proposed bridge year capital expenditures of $900,000 and test year capital expenditures of $472,000 for Corporate Services. The ALJ noted that no party opposed the projected expenditures. PFD, p. 187.

There were no exceptions filed and, therefore, the Commission finds that the company's proposed capital expenditures should be approved.

10. Depreciation

Consumers projected that its total accumulated depreciation and amortization reserve will be $6,698,598,735, which was adjusted to $6,695,979,000 in the company's rebuttal. The Staff recommended a $6.687 billion reserve. The ALJ noted that, "[t]he parties do not appear to dispute the rates to use in the calculation of the accumulated provision for depreciation, and the difference between the company's projected test year accumulated provision for depreciation amount and

Staff's proposed amount was the result of adjustments by Staff to the company's projected capital expenditures." PFD, pp. 187-188.

There were no exceptions filed and, therefore, the Commission approves the calculation of the accumulated provision for depreciation adopted by Consumers and the Staff.

11. Construction Work in Progress

Although Walmart acknowledged the Commission's long-standing practice of including CWIP in rate base, Walmart expressed concern that "[i]ncluding CWIP in rate base results in charges to customers for assets that are not yet 'used and useful' in providing electric service." 8 Tr 4531.

Consumers disagreed, stating that "the return calculated on AFUDC eligible CWIP is offset in the revenue requirement calculation by increasing net operating income with an AFUDC offset. The effect is that there is no requested rate relief for AFUDC eligible projects." 6 Tr 2271. The company asserted that only CWIP that is not AFUDC eligible receives a return and customers are not asked to pay for the asset, but instead pay for the financing costs that would actually be incurred during the construction period. Consumers disputed Walmart's claim that including CWIP in rate base reduces shareholder risk.

The ALJ stated that, "[a]s Consumers points out in its brief, the Commission has previously rejected the same argument by Walmart regarding the propriety of including CWIP in rate base. Given the Commission's consistent affirmation of including CWIP in rate base, the ALJ finds that Walmart's recommendation should be rejected." PFD, p. 189 (footnote omitted).

There were no exceptions filed and, therefore, the Commission adopts the ALJ's findings and conclusions on this issue.

B. Working Capital

Consumers used the balance sheet method approved in the June 11, 1985 order in Case No. U-7350 and projected that its jurisdictional working capital requirement for the test year will be $1,225,087,000. The ALJ noted that the Staff accepts the company's calculation and no other party objected to the method or the resulting working capital amount. In addition, the ALJ stated that, "Consumers requested approval to include projected pre-paid cloud computing expenses in working capital, consistent with generally accepted accounting principles and FERC accounting guidance issued December 20, 2019, in Docket No. AI20-1-000. No party took issue with the company's request, and the ALJ recommends that it be granted." PFD, pp. 188-189.

There were no exceptions filed and, therefore, the Commission approves Consumers' jurisdictional working capital calculation and resulting amount. In addition, the Commission finds that the ALJ's recommendation regarding the projected pre-paid cloud computing expenses is well reasoned and should be approved.

### C. Rate Base

Based on the discussion above, the Commission approves a total jurisdictional electric rate base of $11,660,441,000 for the test year. This is comprised of $10,435,364,000 in adjusted net plant and an allowance for working capital of $1,225,078,000.

## IV. COST OF CAPITAL

As discussed in the PFD, the parties reached agreement on several balances and cost rates for components of Consumers' proposed capital structure. The two remaining areas of dispute concern the appropriate common equity balance and cost rates. The ALJ thoroughly explained the positions of the parties on these issues and will not be repeated here.

A. Common Equity Balance

Consumers proposed a common equity balance of $9.080 billion, which constitutes 52.50% of its permanent capital structure. Consumers argues this regulatory equity ratio is necessary for Consumers to maintain an evenly balanced capital structure. 4 Tr 673-674.

The Staff proposed a common equity balance of $8.587 billion, which constitutes 51.11% of Consumers' permanent capital structure, to conform with the Commission's request for the company to rebalance its capital structure to more equivalent debt-to-equity levels. The Staff contended this balance is less costly for ratepayers and still reasonable for the company to maintain its credit standing and access to capital markets. 8 Tr 3101-3102.

In rebuttal, Consumers argues that the Staff erred in its use of a 25-month average, instead of the correct 13-month average used by the company, the Staff's projected common equity balance would have been $408 million higher, resulting in an equity ratio of 52.26. 4 Tr 702. Consumers also posited that its current credit rating is not indicative of the future and that the negative impacts of the 2017 Tax Cuts and Jobs Act (TCJA) indicates a higher likelihood of a credit rating downgrade in the near future. 4 Tr 709. Furthermore, Consumers highlights the COVID-19 pandemic as another reason for Commission to adopt the company's proposed the equity ratio. 4 Tr 713.

The Attorney General proposed a capital structure with 50% common equity and 50% debt by adopting the permanent capital structure proposed by Consumers, with an increase in long-term debt and a reduction of the same amount in common equity. 8 Tr 3416-3417.

In rebuttal, Consumers argued that the Attorney General's use of the parent company equity level is inappropriate and the Attorney General should be using the equity ratios at the regulated subsidiary level which would result in a 53.2% to 53.0% common equity ratio. 4 Tr 750-751.

ABATE recommended common equity of 51.5% to move towards the Commission's directed goal of a more balanced capital structure. ABATE asserted that Consumers' proposed common equity ratio results in higher costs to ratepayers. 8 Tr 3200. Additionally, ABATE asserted that Consumers' credit ratings would not change if the Commission adopted a lower ROE and common equity ratio than Consumers is requesting. 8 Tr 3152.

In rebuttal, Consumers argued that ABATE failed to address or provide justification for the recommended equity ratio, given that the average of ABATE's own proxy group's equity ratio significantly exceeds ABATE's recommendation. Furthermore, Consumers posited that the impacts of the TCJA and the COVID-19 pandemic will prevent Consumers from reaching a 50% equity ratio by 2023, and that maintaining a 52.5% equity ratio will be appropriate for the foreseeable future. 4 Tr 754.

RCG argued that Consumers' debt to equity ratio should be reduced and that the common equity range recommended by the Staff, and other parties, is appropriate. RCG's brief, p. 17.

The ALJ recommended that the Commission adopt the Staff's proposed common equity balance of $8,587,376,960, which represents approximately 51.11% of the permanent capital structure. The ALJ found that the Staff's recommended common equity balance supports the Commission's objective of a more balanced capital structure that is less costly to ratepayers and yet still reasonable for Consumers to maintain its credit standing and ensure continued access to capital markets. PFD, p. 222. The ALJ found Consumers' proposal to set its common equity balance at 52.5% neither reasonable nor supported by the record. The ALJ pointed out that there was not sufficient evidence presented in this case to indicate that the effect of the TCJA justified deviating from moving towards a balanced capital structure. The ALJ explained factors impacting Consumers' credit rating have not changed since the passage of the TCJA and that Michigan has a very strong regulatory framework, both of which favorably impact Consumers' credit rating. PFD, p. 214.

Consumers takes exception, contending that the ALJ's use of the Staff's calculation of common equity balance and equity ratio is in error and should not be adopted by the Commission. Consumers states that the record demonstrates a change in the company's credit metrics since the passage of the TCJA and, therefore, the ALJ's finding is in error. Consumers argues that it should not have to undergo a credit downgrade in order to prove a change in the company's credit metrics. Consumers reiterates that the threat of a credit downgrade is real and to minimize the importance of key credit impacts such as the TCJA and the COVID-19 pandemic is shortsighted. Consumers also takes exception to the ALJ's implication that the company's 52.5% proposal is a money grab and reiterates the company's concerns about credit metrics, including credit rating agencies' view of Michigan's regulatory environment. Consumers requests that the Commission review the company's concerns and reject the ALJ's recommendation in favor of Consumers' proposed common equity ratio. Consumers' exceptions, pp. 124-144.

The Attorney General takes exception and requests that the Commission adopt a 50/50 capital structure. She reiterates that this aligns with the Commission's directive to move to a balanced structure unless evidence is presented suggesting otherwise. She argues that the company funds a significant part of its equity with long term debt issued at the parent company level and that the company did not support the position that a higher equity cushion is needed to maintain its credit ratings on long term debt. In addition, the Attorney General notes that the common equity ratio of the peer group used in this case is approximately 45%. Attorney General's exceptions, pp. 24-25. Further, the Attorney General agrees that the company's proposal for a common equity balance of 52.50% was neither reasonable nor supported by the record; therefore, she asks the Commission to adopt her recommended equity ratio of 50%. *Id.*, p. 27.

Consumers replies that the Commission should reject the Staff's and the ALJ's proposals to reduce its common equity balance. Consumers reiterates that, for all of the reasons discussed in the company's testimony, briefs, and exceptions, the Commission should adopt its capital structure, including an equity ratio of 52.50%. Consumers argues that continuing to ignore the big picture as it relates to the company's financial metrics and credit quality will affect costs to customers. Consumers' replies to exceptions, p. 35.

In reply, the Staff argues that Consumers' exceptions to the PFD mischaracterize the Staff's testimony. Staff's replies to exceptions, p.33. The Staff maintains that in the company's attempt to explain its actions, it impugns the Staff's experience and expertise in an insulting and disparaging manner. *Id.*, p. 34. According to the Staff, a 51.11% equity ratio is in line with the Commission's stated objective of a more balanced capital structure and will provide cost saving benefits to customers in these stressful times. Therefore, the Staff contends that the Commission should reject Consumers' arguments and adopt the Staff's well-reasoned 51.11% equity-based capital structure. *Id.*, pp. 35-36.

The Attorney General replies that the TCJA does not necessitate the company's proposed equity ratio of 52.50%. The Attorney General argues that the record shows no measurable change in the company's strong credit rating. Additionally, the Attorney General notes that the ALJ weighed the evidence and did not minimize the threat of a credit downgrade. Lastly, the Attorney General states that the Commission should follow its stated objective to require the utilities to present a balanced capital structure. Attorney General's replies to exceptions, pp. 39-42.

In reply, ABATE maintains that Consumers' debt-to-equity ratio is unnecessary and that the Commission should require Consumers to increase the use of long-term and short-term debt and rebalance its capital structure. ABATE's replies to exceptions, pp. 7-10.

The Commission finds the PFD well reasoned and adopts the ALJ's recommendations on this issue. Specifically, the Commission finds that the Staff's recommendation keeps Consumers on track to rebalance its capital structure as the Commission previously ordered, while allowing Consumers to maintain its wide access to capital markets to be reasonable. The Commission therefore adopts a common equity balance of $8.587 billion, or 51.11% of the company's permanent capital structure.

B. Cost Rates

A utility's cost of common equity is generally referred to as the ROE. The ROE is the return that investors expect in order to induce investors to purchase common stock which in turn provides the utility with capital for use in its various operations. The criteria for establishing a fair rate of return for public utilities is rooted in the language of the landmark United States Supreme Court cases *Bluefield Waterworks & Improvement Co v Public Serv Comm of West Virginia*, 262 US 679; 43 S Ct 675; 67 L Ed 1176 (1923), and *Federal Power Comm v Hope Natural Gas Co,* 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944). The Supreme Court has made clear that, in establishing a fair rate of return, consideration should be given to both investors and customers. As stated on page 12 of the December 23, 2008 order in U-15244 (December 23 order), "the rate of return should not be so high as to place an unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise." Nevertheless, the Commission observes that the determination of what is fair or reasonable, "is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use." *Meridian Twp v City of East Lansing,* 342 Mich 734, 749; 71 NW2d 234 (1955). With these principles in mind, the Commission considers the factors that form the basis for determining the appropriate rate of return for Consumers.

Consumers is seeking an authorized ROE of 10.50%, which represents a 50-basis point increase above its currently authorized ROE of 10.00% set in the company's last electric rate case, Case No. U-20134. Consumers stated that the recommendation of 10.50% is in conjunction with the recommended equity ratio of 52.50% provided by the company. 4 Tr 350. Consumers explained that the recommendation is based upon many considerations, including the current state of the economy and capital markets; the need to continue to attract capital and maintain financial strength while undertaking large capital expenditure programs designed to improve safety, reliability, and customer value; the risk profile of Consumers' electric business compared to the proxy group; established principles for setting a fair ROE including ensuring the financial soundness and credit of the utility; and various economic models used to calculate the cost of equity. 4 Tr 350-351.

In determining its ROE recommendation, Consumers considered certain qualitative factors, including the company's good reputation, investors' view of Michigan's positive regulatory environment, uncertainty in the markets, and the company's need to attract capital in light of its plans to make significant investments in the next decade. Consumers further addressed the limitations of various models by employing multiple methodologies, using projections for market inputs (risk-free rates, dividends, and risk premiums), and conversations with and feedback from the investment community. 4 Tr 375-376. After weighing the quantitative results from the various models and the qualitative factors, Consumers recommended the midpoint of its recommended range of 10.00% to 11.00%, an ROE of 10.50%. 4 Tr 376.

The Staff recommended an ROE of 9.75%, the upper end of its calculated range of 8.75% to 9.75%, based on the Discounted Cash Flow (DCF) method, the Capital Asset Pricing Model (CAPM), a bond yield + risk premium method, and a comparison of recent electric ROE determinations from other states. 8 Tr 3106-3107.

The Attorney General recommended an ROE of 9.50%. 8 Tr 3436. The Attorney General also employed the DCF, CAPM, and Utility Risk Premium analyses, arriving at ROE estimates of 9.03% from the DCF method, 7.04% from the CAPM approach, and 8.67% from the Risk Premium analysis, using a revised proxy group. 8 Tr 3439, 3442, 3443; Exhibits AG-41, AG-42, AG-43. Although the average result of the various models was an ROE of 8.44%, the Attorney General adjusted this to a recommended ROE of 9.50% to account for: (1) the current state of the economy and financial markets has increased business risk; (2) the Commission's possible preference for a more gradual reduction and be reluctant to set an ROE for the company at the 8.44% true cost of capital at this time; and (3) the 9.50% proposed ROE is in line with the average ROE granted to other electric utilities by state regulatory commissions around the country during 2019. 8 Tr 3463-3464.

ABATE used a single-stage DCF method with a constant growth rate (which resulted in an average ROE of 9.20% and an ROE range of 8.70%-9.80%), a multi-stage DCF method with varying growth rates (which produced an average of 8.40% and a range of 8.20%-8.90%), two CAPM methods (which estimated ROE at 6.20% and 11.60%, respectively), and two risk premium methods (which estimated the ROE at 7.60% and 7.51%, respectively), to arrive at an ROE recommendation of 8.90%, within their range of 6.20% to 11.60%. 8 Tr 3144, 3164, 3171, 3173, 3175, 3179, 3181. ABATE also pointed out that that Consumers' estimated ROE is 8.10% using

ABATE's revised CAPM, Risk Premium, and DCF analyses and Consumers' proxy group. 8 Tr 3193.

In response, Consumers posited that the implied Funds From Operations to Debt ratios that were calculated based on the recommendations from the Staff, the Attorney General, and ABATE (18.20%, 17.30% and 17.50%, respectively) are all drastically lower than the 20% threshold recommended by Consumers. 4 Tr 418-419. Consumers argued that there has been a major change in underlying economic conditions due to the ongoing global COVID-19 pandemic, which warrants a significant increase in the authorized ROE. 4 Tr 420. Consumers added that the impacts of the TCJA have led to a credit quality deterioration across the utility sector, which would suggest the need for an upward movement in Consumers' ROE, equity ratio, or both. 4 Tr 421.

In rebuttal, ABATE challenged the Staff's and the Attorney General's ROE analyses. ABATE posited that the Staff's recommended ROE is influenced by Consumers' currently authorized ROE rather than an analytically determined ROE and is not supported by risk-mitigating factors. 8 Tr 3234. ABATE disagreed with the Attorney General's adjusted calculations for an estimated average ROE. ABATE argued that the Attorney General's adjustments are inconsistent with accepted accounting practices, she ignores Consumers' numerous risk-mitigating factors, and her 106-basis-point increase to her estimated average ROE increases Consumers' revenue requirement by $72.5 million. 8 Tr 3238.

The MEC Coalition requested that the company's ROE be set at approximately the 35th percentile of the range of reasonable ROEs. Additionally, the MEC Coalition argues that performance be considered when setting the ROE. MEC Coalition's initial brief, pp. 182-193; MEC Coalition's reply brief, pp. 8-12.

The ALJ recommended that the Commission adopt an ROE of 10.00%. The ALJ based her conclusion on the various proposals presented, the criteria supported by the Commission and the courts, and the lack of a precise mathematical formula to determine the appropriate ROE. As the Commission has previously stated, the rate of return "should not be so high as to place an unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise." December 23 order, p. 12. The ALJ found Consumers' recommended ROE of 10.50% excessive based on its current strong credit rating, even when accounting for the TCJA, the opportunity to refinance debt and lower cost of capital due to lower interest rates, a receptive market for new long-term debt during the COVID-19 pandemic, and a strong regulatory network – all of which reduce Consumers' risk and income variability and favorably impact Consumers' credit rating. Additionally, the ALJ asserted that the devastating impact of the pandemic on Consumers' ratepayers provides the appropriate backdrop against which the reasonableness of the increased costs to the ratepayers must be evaluated. PFD, pp. 255-256. The ALJ further noted that the authorized ROEs approved by other commissions for electric utilities have generally declined in recent years, with the average authorized returns generally within the range of 9.50% to 9.72%. 6 Tr 1741, Exhibit S-4, Schedule D-5. p. 12; 7 Tr 2446-2447, Exhibit AG-49; 7 Tr 2168, 2172; Exhibit AB-6. Additionally, the ALJ found that the ROEs recommended by the Staff, the Attorney General, and ABATE could be unduly harmful to the company's credit ratings given the current economy and pandemic and should not be adopted. The ALJ recommended an ROE of 10.00% as it will assure reasonable access to capital with favorable terms and conditions, while remaining cognizant of the burden on ratepayers. PFD, pp. 266-267.

In exceptions, Consumers argues that the PFD's proposed ROE of 10.00% does not satisfy the standards under *Bluefield* and *Hope* and utilizes the same erroneous reasoning used to recommend a lower equity ratio. Consumers further takes exception to the ALJ's use of the settlement agreement in Case No. U-20650 on pages 262-263 of the PFD as the basis for her recommendation in this case. Although Consumers requests that the Commission authorize an ROE of 10.50%, the company will accept an ROE of 10.00% provided the Commission approves the capital structure and equity ratio requested by the company. Consumers' exceptions, pp. 144-148.

The Staff acknowledges the ALJ's discussion on ROE was detailed and thorough, however the Staff disagrees with the recommended 10.00% ROE. The Staff argues that the ALJ's recommendation is unduly high and unnecessary. The Staff asserts its recommended 9.75% ROE is at the high end of its 8.75%-9.75% ROE range and is higher than the 9.50% national average ROE for electric utilities in the first quarter of 2020. Staff's exceptions, pp. 5-6. Furthermore, the Staff posits that the current low-interest-rate environment, coupled with the ALJ's recommendation to grant the company's requested cost recovery mechanisms, substantially reduces the company's business and financial risk. *Id.*, p. 6. The Staff requests that the Commission reject the 10.00% ROE recommendation of the ALJ and accept the favorable and more balanced 9.75% ROE recommended by the Staff. *Id.*, pp. 6-7.

The Attorney General takes exception to the ALJ's recommended 10.00% ROE. Although the ALJ recognized that the company's proposed ROE places an undue burden on ratepayers, she rejected the company's arguments regarding the impact of the TCJA, and she agreed that the company's analyses were based on flawed assumptions, the Attorney General asserts that the ALJ proposed an ROE higher than those approved by commissions nation-wide in recent years, with the average ROE within the range of 9.50% to 9.72%. Attorney General's exceptions, pp. 27-28.

The Attorney General argues that the Commission has authorized lower ROEs in recent orders and that a 9.50% ROE is a very conservative estimate as a transition to the true cost of equity at 8.44%. *Id.*, pp. 30-31.

ABATE takes exception to the ALJ's recommended 10.00% ROE, asserting that the ALJ's recommendation is excessive and unreasonable and should be rejected. ABATE's exceptions, p. 9. ABATE argues that the Commission has sought to balance the interest of investors with those of ratepayers and, in the past, has approved ROEs lower than those proposed by utility experts. *Id.*, p. 10. ABATE contends that an ROE of 8.90% is not only consistent with the balance of interests but also with the evidence presented in this case. *Id.* ABATE agrees with the ALJ that Consumers' proposed ROE of 10.50% is excessive. However, ABATE argues that the ALJ's recommendation is also excessive based on her reasoning in the PFD. *Id.*, pp. 11-12. ABATE asserts that an ROE below 10% will not adversely affect Consumers' access to capital markets at competitive rates, it will bring Consumers in line with national averages, and it will alleviate some of the burden on ratepayers. *Id.*, p. 12. For these reasons, ABATE requests that the Commission reject the ALJ's recommendation and adopt an ROE comparable to ABATE's proposal of 8.90%. *Id.*, p. 13.

In exceptions, RCG asserts that the recommended 10.00% ROE is unacceptably high and that the Commission should adopt the ROE recommendation of the Staff and other parties. RCG argues that the Commission should not approve an excessive ROE simply because the financial status and credit rating of the parent company are low. RCG urges the Commission to adopt an ROE significantly lower than the ALJ's recommendation, such as that presented by the Staff and other parties in this case. RCG's exceptions, pp. 21-23.

The MEC Coalition takes exception, arguing that the ALJ erred in failing to set the ROE based on performance metrics. MEC Coalition's Exceptions, pp. 2-5.

In reply, Consumers reiterates its willingness to accept the recommended ROE of 10.00% provided the Commission approves the capital structure and equity ratio requested by the company. Consumers' replies to exceptions, p. 39. Further, Consumers argues that the Staff's exceptions are in error, lack merit, and should be rejected by the Commission. *Id.* Consumers asserts that its ROE should be higher to compensate investors for the increased risk they assume when making an investment in equity rather than debt. *Id.*, pp. 42-43. In addition, Consumers replies that the ROE must counter the effects of the TCJA and the COVID-19 pandemic on the company's credit outlook. *Id.,* p. 45. Finally, Consumers argues that an ROE below 10.00% would not be just and reasonable and would send the wrong message to investors. *Id.*

The Staff replies that the Commission should reject the ALJ's 10.00% ROE because the record evidence supports an ROE closer to the Staff's proposal. The Staff posits that, if the Commission rejects the ALJ's recommendation because it was based on a previous settlement agreement, then the Commission should adopt the Staff's ROE recommendation of 9.75%. Staff's replies to exceptions, pp. 36-37.

In reply, the Attorney General maintains that Consumers' request for an ROE of 10.50% is excessive and that the Commission should adopt an ROE below 10.00%. The Attorney General argues that an ROE of 9.50% or less is supported by the evidence and provides the company's investors with an ample return on their investment. Furthermore, she asserts that an ROE of less than 10.00% is consistent with the ROEs for similarly situated utilities. And, although the Attorney General believes that the ALJ's recommended ROE of 10.00% is too generous, the company's singular focus on a perceived misuse of settlement terms ignores the ALJ's analysis that considered a number of factors and should be given no weight. Finally, the Attorney General contends that the Commission is within its purview to review not only past Consumers' cases but all previous precedent, including ROEs in comparable and recently decided cases, such as the May 5, 2020 order in Case No. U-20561 wherein the Commission reduced DTE Electric Company's (DTE Electric's) ROE from 10.00% to 9.90%. Attorney General's replies to exceptions, pp. 42-43.

In reply, ABATE maintains that the company's proposal and the ALJ's recommendation are unreasonable and should be rejected. ABATE argues that the record in this case indicates that Consumers' support for a higher ROE is overstated and unreasonable. Further, ABATE states that, to lower customers' cost burden during unprecedented times, the Commission should reject the company's exception and the ALJ's recommendation and approve ABATE's recommended 8.90% ROE. ABATE's replies to exceptions, pp. 10-11.

The MEC Coalition replies that the ALJ's use of the settlement agreement terms in Case No. U-20650 to set the ROE was not inappropriate. The MEC Coalition contends that the ALJ referenced the Commission's final order in Case No. U-20650 and described the terms of the settlement agreement. MEC Coalition's replies to exceptions, p. 90. The MEC Coalition also concurs with the Staff's and the Attorney General's exceptions, but for different reasons. The MEC Coalition contends that Consumers lags behind peer group utilities in reliability, affordability, and environmental metrics and, therefore, Consumers' ROE should be reflective of the company's performance. The MEC Coalition requests that the Commission reject the ALJ's recommendation and adopt an ROE that aligns with the mediocre performance of the company. *Id.*, pp. 91-92.

The Commission finds that an ROE of 9.90% will best achieve the goal of providing appropriate compensation for risk, ensuring the financial soundness of the business and maintaining a strong ability to attract capital. The Commission agrees with the ALJ that Consumers' proposed 10.50% ROE is excessive and out of line with current market trends. The Commission finds, however, that it is appropriate to reduce the ALJ's recommended 10% ROE by 10 basis points because this is consistent with other ROEs approved by the Commission and strikes a balance to ensure the company's financial health while not placing unnecessary burden on ratepayers. While the 9.9% ROE is still above national average and the intervenors' recommended ROEs using various financial models, the Commission is mindful of its decision to continue on the glidepath to a more balanced capital structure as set forth in this order. The Commission finds that the lower equity portion in the capital structure, combined with the 9.9% ROE, is reasonable based on the record, Commission precedent, and legal standards.

Agreeing with the ALJ, the Commission finds that the 10.50% ROE requested by the company is inappropriate. In setting the ROE at 9.90%, the Commission believes there is an opportunity for the company to earn a fair return during this period of atypical market conditions. This decision also reinforces the belief, as stated in the Commission's March 29 order, "that customers do not benefit from a lower ROE if it means the utility has difficulty accessing capital at attractive terms and in a timely manner." These conditions still hold true based on the evidence in the instant case. The fact that other utilities have been able to access capital despite lower ROEs, as argued by many intervenors, is also a relevant consideration. It is also important to consider how extreme market reactions to global events, as have occurred in the recent past, may impact how easily capital will be able to be accessed during the future test period should an unforeseen market shock occur. The Commission will continue to monitor a variety of market factors in future rate cases to gauge whether volatility and uncertainty continue to be prevalent issues that merit more consideration in setting the ROE.

C. Overall Rate of Return

Based on the foregoing discussion, the Commission adopts a 48.89%/51.11% debt to equity permanent capital structure, a long-term debt cost rate of 3.81%, an ROE of 9.90%, and an overall weighted cost of capital of 5.67%, as shown on the following table:

| Description | Amount (000) | Ratio | Cost Rate | Weighted Cost |
|---|---|---|---|---|
| Long-Term Debt | $8,178,497 | 39.53% | 3.81% | 1.51% |
| Preferred Stock | $ 37,315 | 0.18% | 4.50% | 0.01% |
| Common Equity | $8,587,377 | 41.50% | 9.90% | 4.11% |
| Short-Term Debt | $ 138,800 | 0.67% | 2.03% | 0.01% |
| Deferred Fed Inc. Tax | $3,655,000 | 17.66% | 0.00% | 0.00% |
| JDITC Debt | $ 45,752 | 0.22% | 3.81% | 0.01% |
| JDITC Preferred Stock | $ 209 | 0.00% | 4.50% | 0.00% |
| JDITC Equity | $ 48,039 | 0.23% | 9.90% | 0.02% |
| Total | $20,690,989 | 100.00% | | 5.67% |

## V. ADJUSTED NET OPERATING INCOME

Net operating income (NOI) is calculated by subtracting the company's operating expenses including depreciation, taxes, and AFUDC, from the company's operating revenue. Adjusted NOI includes the ratemaking adjustments to the recorded NOI test year for projections and disallowances. The ALJ provided a thorough analysis of the issues and arguments in adjusted NOI on pages 269 through 315 of her PFD, which will not be extensively repeated here. The issues raised therein are addressed below, *ad seriatim*.

A. Sales and Revenue Forecast

The ALJ stated in her PFD that Consumers projected jurisdictional electric deliveries of 34,131 gigawatt-hours inclusive of full service and choice[9] customers, adjustments to electric deliveries and peak demand to account for EWR and DR programs, and an increased line-loss factor of 7.73%. The ALJ agreed with Energy Michigan's position that Consumers should calculate a separate line-loss factor for choice customers[10] because they typically have lower line losses than secondary commercial class customers, and thus the 7.73% factor results in inaccurate cost allocation for choice customers. The ALJ recommended that, in future rate cases, Consumers should correct its line-loss calculations using Energy Michigan's method of calculation. PFD, p. 270.

The ALJ further stated that the Staff accepted Consumers' initial sales forecast of $4.358 billion, which includes credits for residential senior citizen (RSC) and residential income assistance (RIA), and, ergo, the Staff accepted the $5,421,000 reduction to the forecast that Consumers introduced on rebuttal to account for a reduced number of streetlights under general service unmetered street lighting, Rate GUL. However, the ALJ stated her agreement with the Staff's residential DR credit, which was $222,000 greater than Consumers' residential DR credit projection. PFD, p. 270.

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[9] Choice is also known as retail open access.

[10] Energy Michigan recommended an updated 2.53% line loss factor for choice load. PFD, p. 270.

Consumers takes exception to the ALJ's recommendation, repeating its argument that, while the company agrees that its 7.73% line loss is overstated for choice customers, its forecasting procedure incorporates the most recent Commission-approved methodology and is correctly applied without distinguishing choice customers. The company argues that changing the line loss projections for the choice customer category would have no impact on allocated costs because the company's cost of service study (COSS) does not use projected system output figures for cost allocations, thereby making Energy Michigan's suggestion inconsequential.
Consumers' exceptions, p. 148.

Energy Michigan replies that the Commission should reject Consumers' 7.2% line loss projection for choice customers because the parties agree that the projection is too high. Energy Michigan reiterates that a correct line loss factor is essential to evaluate the efficacy of programs that may affect line loss and that inaccurate projection of line losses for choice customers could result in incorrect allocation of costs. Energy Michigan's replies to exceptions, pp. 7-8.

The Commission is persuaded, as was the ALJ, that Energy Michigan's argument has merit and that, in future rate cases, Consumers should use correct line loss factors for choice customers. However, in the instant case, the Commission finds that Consumers' sales forecast and revenue projections are acceptable and supported in the record and, therefore, the Commission adopts the projections as set forth in the PFD on pages 268-270.

B. Fuel, Purchased, and Interchange Power Expense

In her PFD, the ALJ stated that Consumers' projected power supply costs for the test year was approximately $2.1 billion and that the Staff incorporated the same values in preparing its analysis. The ALJ indicated that no party stated an opposition to the figures. PFD, p. 270.

The Commission finds that Consumers' projected power supply costs for the test year of $2,160,757,000 is reasonable, supported by record evidence, consistent with previously approved forecasting methods, and uncontested, and, therefore, is adopted.

C. Other Operating and Maintenance Expense

The ALJ stated that, on rebuttal, Consumers lowered its initial projection of O&M expenses from $684,695,000[11] to $673,866,000. She stated that the MEC Coalition agreed with the Staff's lower recommended projected test year O&M expenses of $624,350,000 and that the Attorney General recommended even lower O&M projected expenses of $585,700,000. PFD, pp. 270-271. Consumers' projections included the line-items discussed in subsections 1 through 14 below, beginning with a discussion of inflation factors in subsection 1.

1. Inflation Factor Bifurcation

The ALJ stated in her PFD that the treatment of inflation as it relates to several expense categories was a matter of controversy in the case and that one area of particular difference of opinion among the parties was the bifurcation of labor and nonlabor elements of corporate services expenses and the application of separate inflation factors applied to labor and nonlabor projections. The PFD stated that Consumers made its O&M expense calculations and projections using a Consumer Price Index (CPI) factor for corporate services expenses (2% to 2.3%)[12] and a higher factor (3.2%) for labor, justifying this practice with the argument that, unless the higher inflation factor was applied to labor cost projections, the company would be in danger of paying below

[11] Consumers' initial O&M expense projection represented a $110.7 million (19.3%) increase over 2018 historical test year expenses. PFD, p. 271.

[12] Consumers projected an inflation factor for nonlabor corporate services of 2% for 2019,1.5% for 2020, and 2.3% for 2021, taken from the November 2019 non-labor IHS Markit forecast. PFD, p. 272.

market wages and would have difficulty attracting and retaining a quality workforce.[13] PFD, pp. 271-274. The ALJ noted that the Staff and the Attorney General argued, among other things, that a single inflation factor should be applied collectively to all expenses; with the Staff arguing that the company controls the wage increases that it pays its employees, and the Attorney General arguing that bifurcation results in a blended inflation rate that is higher than the CPI. The ALJ also stated that the Staff recommended using the average values from multiple sources to project inflation factors, which, in this instance, resulted in lower inflation factors than those in Consumers projection.[14] *Id.*, pp. 272-273.

The ALJ recommended that the Commission reject Consumers' bifurcated inflation factor projections and, instead, adopt the Staff's method of calculating the factors using the average of multiple sources for projections that are applicable collectively to labor and nonlabor expenses.[15] She further recommended that the Commission reject a higher inflation rate for labor expenses, reasoning that labor costs are a component of the goods and services that constitute the CPI and that Consumers had not established whether, once labor costs are removed, the use of the CPI is appropriate or reliable for nonlabor expenses. PFD, pp. 275-276. Additionally, the ALJ reasoned that Consumers' application of a labor-only inflation factor based solely on wage costs fails to consider productivity increases that are associated with increased capital expenditures. *Id.*, p. 275.

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[13] The ALJ stated that "[w]hile Consumers cites the Commission's order in Case No. U-20322, a dispute regarding the use of a labor inflation rate was not presented to the Commission for resolution in that case." PFD, p. 276.

[14] The Staff derived its calculations from researching and averaging several sources and recommended inflation factors of 1.81% for 2019, 1.61% for 2020, and 2.26% for 2021. PFD, pp. 272-273; 8 Tr 4725.

[15] The Staff recommended inflation factors of 1.81% for 2019, 1.61% for 2020, and 2.26% for 2021. PFD, pp. 272-273; Consumers' exceptions, p. 149.

Consumers takes exception to the ALJ's recommendation. Consumers states that it agreed to the Staff's proposed updated inflation factors and the corresponding reduction of $24,000 to its nonlabor corporate services expense projection, but the company remains opposed to the application of the Staff's calculations to its labor expense because the ALJ failed to consider that different circumstances may affect labor and labor-related inflation rates as opposed to nonlabor costs, and failed to consider the merit raises that Consumers plans to give its employees. Consumers argues that its 3.2% labor inflation rate was developed using independent third-party sources. Consumers reiterates an analogous example provided in its testimony that a low inventory of homes for sale may drive up housing costs and, in turn, increase the CPI, but that low inventory may have no impact on labor costs. Consumers' exceptions, pp. 149-150; 6 Tr 1855.

Consumers further argues that the ALJ's reliance on the May 19, 2019 order in Case No. U-20162 (May 19 order) to support a non-bifurcated inflation factor is misplaced because, in the May 19 order, the Commission rejected a composite labor/nonlabor inflation rate because there was insufficient evidence to approve it. Consumers argues that, in the instant case, the company did not propose a composite rate and that the May 19 order cannot be relied on as precedent because it stated a rejection of the concept due to insufficient evidence and not a rejection of the concept itself. The company pointed out that the Commission had previously approved corporate services expenses that were calculated in the same manner as in the instant case. *Id.*, p. 151.

The Commission finds the ALJ's analysis of the issue and recommendation against bifurcation of inflation rates and higher labor inflation to be well reasoned and supported in the record. The Commission is not persuaded by Consumers' arguments for a bifurcated inflation rate for labor and nonlabor, and further finds that Consumers' 3.2% projected inflation rate for labor should be rejected because it is based on unacceptable projection metrics that were not satisfactorily proven in the record to be reliable. In addition, the Commission has historically rejected the concept of a blended inflation rate.[16] Therefore, the Commission adopts the ALJ's recommendations in this matter.

2. Electric Distribution and Energy Supply

Consumers projected test year expenses in the amount of $170.7 million for electric distribution and energy supply, an increase of approximately $30 million over historical test year expenditures. PFD, p. 276.

a. The Commission Staff's Inflation Adjustment

The Staff asserted that Consumers had attributed test year expenses to inflation without sufficient supporting documentation to establish what costs were being inflated and whether the costs were appropriately inflated, particularly the projections set forth on Exhibits A-36 and A-75. PFD, p. 277. The Staff testified that it found it difficult to determine the basis for Consumers' projections because supporting and explanatory details were not clearly stated on its exhibits and that spreadsheets with intact formulas and cell references to support Consumers' projections had been requested but were not supplied. *Id.*, pp. 277-278. According to the Staff, Consumers did not supply complete documentation to clarify apparent inconsistencies in the inflation rates applied to service restoration costs as requested by the Attorney General. Accordingly, the Staff argued that the expenses could not be verified and the inflation component of $12,584,000 (as set forth in Exhibit A-36) should be excluded from Consumers' test year expense projection. *Id.*, p. 278.

[16] The May 8 order, p. 186, states:

> DTE Electric has not provided sufficient evidence in this case to induce the Commission to depart from its decisions in previous rate cases rejecting the blended inflation rate. The Commission agrees with the Staff that, while DTE Electric will see some inflation, the company will also offset some of the inflation with productivity gains.

In rebuttal, Consumers argued that its electric distribution projection for the 2021 test year was not based on inflation and that the Staff's suggested exclusion would be the equivalent of setting a 0% inflation rate. Consumers further testified that its Exhibit A-198 sets forth the company's calculation for inflation applied to distribution and that the Staff used an incorrect inflation factor that prevented it from corroborating Consumers' figures on Exhibit A-36. Consumers also asserted that the company now understands that a much higher level of detail in its exhibits is required than in the past. PFD, pp. 278-279.

The ALJ found the Staff's analysis to be persuasive and noted that the Staff called for improved transparency in cost projections and that it prefers a format in which each year's expenses are clearly stated with explanatory comments and formulas to support the figures, without which it may be difficult to determine whether expenses are appropriately included, appropriately inflated, supported by evidence, and inconsistencies are identified. PFD, pp. 277, 280-281. The ALJ found that the Staff must be able to understand the details and relevance thereof that support Consumers' calculations and exhibits. She found that it was reasonable to exclude costs of $12,584,000 from the company's projections because the expense was not sufficiently explained and supported despite the Staff's and the Attorney General's requests for more information. *Id.*, p. 281. The ALJ also recommended that the Commission reject $2.17 million for inflation projections that the company asserts are embedded in Exhibit A-75. *Id.*

Consumers takes exception to the ALJ's recommendation to disallow $12,584,000 in expenses attributable to inflation from its projections, and argues that the Staff's position is refuted in the record and is unreasonable, in part because it renders the projection with no allowance for inflation. Consumers argues that its exhibits (A-36 through A-39) contain the details that the Staff complained were lacking, and the company's projection process was summarized in Exhibit

A-198. Consumers further argues that it is not necessary to trace the inflation adjustment from the projected test year back to the historical test year, thereby negating the Staff's position that the company's figures were not auditable. Finally, Consumers argues that the Staff should have presented an analysis of the company's projected work and projects to prove they are valid, and reiterates that deductions from its projections could impair or prevent Consumers from carrying out its capital plan. Consumers' exceptions, pp. 151-155.

The Commission finds that the ALJ provided a well-reasoned analysis of the parties' positions and supporting exhibits, and agrees with the ALJ's conclusion that Consumers did not supply sufficient support to identify its inflation projections and the manner in which they were calculated. Accordingly, the Commission adopts the ALJ's recommendations and finds that $12,584,000 attributed to inflation set forth in Exhibit A-36 and $2.17 million attributed to inflation embedded in the projections set forth in Exhibit A-75 should be excluded from the company's projections.

b. Future Inflation Estimates

The Staff requested that the Commission require Consumers to improve the transparency of its cost projections in the future. The Staff stated that it prefers a format in which expenses and inflation are clearly set forth for each year with explanatory notes and supporting documentation, thereby preventing distortions of year-to-year costs. The Attorney General also argued that "it is inappropriate to carry over expense items that should be excluded from the 2018 base, and subtract them after inflation has been applied to the higher value." PFD, p. 281. Consumers did not object to the Staff's request for greater transparency. *Id.*

The Commission finds that the matter of increased transparency in Consumers' projections through added documentation and explanation is an area in which the company has room for improvement, particularly because the parties in the instant case were not able to authenticate the validity of all Consumers' projections, resulting in downward adjustments to figures that were insufficiently supported in the record. Accordingly, the Commission finds that, in future filings, Consumers shall provide projections supported by documentation that is consistent with the Staff's recommendations, as stated in the record of the instant case.

c. Storm Restoration Expense and Deferral

Consumers' projected storm restoration expenses of $65 million are based on a three-year average, and the company supported this approximately $11.2 million (21%) increase over 2018 expenses with the explanation that increased storm activity in recent years had increased the company's storm restoration costs. The ALJ agreed with the Attorney General and the Staff that Consumers' storm restoration expenses should be based on a five-year average because that time frame would more accurately capture a true average, rather than a three-year average that includes the unusually high expenses of two years. PFD, p. 282. The ALJ recommended that $11.1 million for service restoration be excluded based on the five-year average of actual service restoration costs as argued by the Staff, the MEC Coalition, and the Attorney General. *Id.*, p. 283.

Consumers takes exception to the ALJ's recommended reduction of $11.1 million and argues that its projection is valid because, in the past four years, the company has experienced numerous ice storms, high wind events, tree outages, and other events that caused power outages and an increased need for mutual assistance (MA). Consumers' exceptions, p. 156. Consumers asserts that MA crewing (which normally comes to Michigan from out-of-state and requires costly travel expenses and lodging) is deployed when all the company's other resources are in operation but cannot keep up with storm restoration. *Id.* However, Consumers also notes that, if the Commission agrees with the Staff's position, then the company should use a five-year average to calculate its storm restoration expense projection, then the inflation applied to the projection should be adjusted as well, which Consumers argues would increase the Staff's recommended storm restoration projection by $2 million. *Id*., p. 157.

The Attorney General replies that Consumers' use of a three-year average to project storm restoration expenses is faulty because the five-year average was approved by the Commission in DTE Electric's recent rate case,[17] because Consumers conceded that the unusually high expenses of 2019 are not likely to be repeated, and, historically, there have been other periods of time in which severe weather occurred over a three-year time frame. Attorney General's replies to exceptions, p. 44.

The Commission agrees with the ALJ that Consumers' storm restoration projection should be based on a five-year average. Consumers' argument that a three-year average captures unusually high restoration costs in recent years is precisely the reason that the Commission prefers a five-year average: a five-year average, in this case, tends to provide a more accurate projection because it flattens, but does not eliminate, the effects of unusually high cost years due to a cycle of damaging weather (and would also have the reverse effect for unusually low-cost years). Further, the Commission is persuaded that Consumers' projected 21% increase over 2018 costs is excessive and lacks a supportable premise (i.e. that future projections should be based on the unusually high expenses of a few recent years) and that the record supports the Staff's suggested storm restoration projection of $54 million based on a five-year average without further adjustments to include additional inflation amounts. Accordingly, the Commission adopts the ALJ's recommendation that Consumers' storm restoration projection be adjusted downward by $11.1 million from $65.1 million to $54 million.

[17] *See*, the May 8 order.

Next, Consumers requested authorization for a one-way storm restoration expense tracking mechanism that uses the company's three-year average storm expense projection amount of $65 million as a base and permits any storm restoration expenses that exceed $75 million to be deferred. Consumers stated that the company cancelled its storm insurance policy because it was not cost-effective and that the cancellation eliminates the $8.3 million insurance premium,[18] ensuring that customers pay only actual restoration costs. PFD, p. 285.

The Staff, the Attorney General, and ABATE disagree with Consumers that a storm restoration expense tracking mechanism is needed. The Staff asserted that its $54 million projection for service restoration is sufficient and exceeds past annual spending on this line item. Further, the Staff asserted that the Commission has not authorized DTE Electric to use deferred accounting for service restoration expense, while the Attorney General pointed out that Consumers has capitalized service restoration in the past five years and has fully recovered those costs.

Consumers countered that service restoration expenses are dependent on the individualized features of each service territory and asserted that other states permit such trackers but conceded that it would agree to a two-way tracker rather than the one-way tracker that the company proposed. PFD, pp. 285-286.

The ALJ recommended that the Commission deny the service restoration tracking mechanism for the reasons stated above by the Attorney General and the Staff. PFD, p. 286.

Consumers objects to the ALJ's recommendation to deny the company's requested deferred recovery mechanism for storm restoration costs above $75 million. Consumers argues its

[18] Consumers testified to the savings of an $8.3 million insurance policy renewal fee that occurred because the company did not renew its storm loss insurance policy for 2020 (*See*, 6 Tr 1837). However, Consumers' Exhibit A-62 indicates the annual expense for storm insurance was $3.3 million. The reason for this apparent discrepancy is unclear.

mechanism will allow for efficient recovery and align with similar mechanisms in other states. However, to address concerns that the proposed mechanism would operate in only one direction, Consumers notes that it would agree to two-way tracker. Consumers' exceptions, p. 158.

The Commission has examined and reviewed the positions of the parties and is persuaded that Consumers' proposal for a storm tracking mechanism, either one-way or two-way, should be rejected for the reasons attributed to the Staff and the Attorney General in the discussion above. Therefore, the Commission rejects Consumers' proposal for a storm tracking mechanism.

d. Miscellaneous Electric Distribution and Supply Issues

The Attorney General asserted that Consumers' O&M increases for LVD device management and grid management were unsupported. PFD, pp. 283-284. Additionally, the Attorney General argued that, although the company's forecasted retirements and new hires for the next three years were consistent with the historical figures from the past five years, Consumers' projections for the cost of training new hires to replace retiring workers are higher than need be. In response, Consumers denied that its projections for retirements and rehires are in line with historical figures and contended that the company cannot rely on historical figures because it expects retirements to increase by 34% over the number of retirements that occurred during the past six years.

The ALJ found that Consumers' estimates of expected retirements and new hires to be supported in the record, whereas the Attorney General's arguments were unsupported and lacked sufficient detail. PFD, pp. 284-285.

The Commission finds Consumers' projections regarding the number of expected retirees and new hires to replace them, as well as projected training costs (subject to downward adjustment for the removal of the labor-only inflation rate), to be reasonable, prudent, and supported in the record and, accordingly, adopts the ALJ's recommendations on the matter.

3. Line Clearing

Consumers significantly increased its projection for line clearing because the company wants to decrease its LVD line-clearing cycle from 14.2 years to 7 years, explaining that the $84 million[19] projection was justified because trees are a significant cause of LVD electrical outages. The Staff recommended that the Commission approve the projection with the added caveat that Consumers be required to provide an annual report containing specific information related to line clearing. PFD, pp. 286-287. Consumers responded that such a report was not necessary because the company currently provides the Staff with the requested information and meets with the Staff once per year. *Id.*, p. 287.

The Attorney General expressed her general agreement with the increase but was concerned that Consumers' line-clearing costs had doubled between 2004 and 2018, with the 2018 increase amounting to over twice the CPI increase for the same period.[20] The Attorney General further stated that Consumers' plan to avoid escalation of crews by working current crews overtime was ineffective and that a gradual line-clearing escalation would permit the company to hire and train workers so that overtime premiums would not be required to meet line-clearing goals. The Attorney General proposed that recovery be tied to the number of miles cleared and that spending be limited to $68 million, with any spending over $84 million to be deferred and amortized over a five-year period. PFD, pp. 287-288; Attorney General's initial brief, pp. 134-135.

Consumers responded that its 2021 contracts for clearing work have been signed and that the company will be billed for straight time except for Saturdays and Sundays. Consumers further

[19] $71.430 million of the $84 million projection will be directed toward LVD line clearing beginning in 2021. PFD, p. 287.

[20] The CPI increase for 2018 was 2.1%; Consumers' increase for line clearing per mile is 5%. Attorney General's initial brief, p. 134.

stated that the contracts contain an inflationary index limiting costs to any average increase of 1.2% annually for five years and 1.8% for ten years, an amount that is well below the CPI. PFD, p. 288.

The ALJ recommended that the Commission approve Consumers' projected $84 million for vegetation management, finding Consumers' plan to be reasonable. Further, she recommended that the Commission require an annual report as discussed by the Staff. Additionally, she recommended that the Attorney General's suggestion that excess expenses be deferred and amortized be denied because deferral and amortization of these expenses would cost more than paying the expenses in current rates.

Consumers takes exception to the ALJ's suggestion that an annual report to the Commission should be required for line-clearing activities and indicates that continued face-to-face meetings with the Staff to review program efficacy is sufficient. Consumers' exceptions, p. 159.

In her exceptions, the Attorney General reiterates her proposed changes to the line-clearing projection (set forth above) and argues that Consumers is unlikely to be able to meet its line-clearing goals and that the Attorney General's suggested limitations will permit Consumers to make sufficient recovery without overburdening ratepayers. Attorney General's exceptions, pp. 33-34.

In her replies to Consumers' exceptions, the Attorney General argues that Consumers conceded that the company's 2019 MA costs were unusual and not likely to be repeated. Attorney General's replies to exceptions, p. 45.

The Commission finds the ALJ's recommendations on vegetation management and line clearing to be persuasive, well reasoned, and supported in the record. Reducing the number and duration of outages through an effective vegetation management program with a shorter line-clearing cycle is prudent because it will help improve service quality for customers, while mitigating against the escalation of storm restoration costs in both O&M and capital categories. Follow-through on the execution of the accelerated tree trimming program is essential to achieve these goals. Accordingly, the Commission adopts the ALJ's findings and conclusions, including the requirement that Consumers file an annual report, as well as meet periodically with the Staff throughout the year to evaluate Consumers' progress toward its line-clearing goals, to refine program metrics, and discuss future strategies.

4. Fossil and Hydro Generation

The ALJ reported that Consumers and the Staff agreed that the current projection in the fossil and hydro generation category of $167 million should be reduced by $7.4 million in projected expenses that were included for the Karn Retention and Separation plan with the $7.4 million deferred as a regulatory asset.[21]

a. MEC Coalition Adjustments

The ALJ stated in her PFD that:

> As discussed in section IV.A.3 [of the PFD] above, the MEC [Coalition] argues that capital and major maintenance costs for Campbell units 1 and 2 that are avoidable under an early retirement scenario should not be included in projected test year expense projections. Exhibits A-70 and MEC-83 identify avoided major maintenance (O&M) costs totaling $672,000 that are avoidable under both a 2024 and 2025 retirement scenario. As also discussed above, Consumers objects to excluding the avoidable costs. For the reasons discussed above, this PFD finds the MEC [Coalition's] argument persuasive that avoidable costs should be avoided until the forthcoming retirement analysis is evaluated in the company's 2021 IRP, resulting in a $672,000 reduction in the company's O&M expense projection.
>
> The MEC [Coalition] also argues that two major maintenance projects planned for the Campbell units for 2021 should be excluded from test year expense projections, based on [the MEC Coalition's witness] Mr. Comings' testimony that the two

[21] *See*, discussion in Section VII.L. of the PFD, pp. 363-364. *See also*, Schedule C5 of Exhibit A-13, and Exhibit A-70.

> projects, Landfill-Clean Dry Ash Silo and Screenhouse and Tunnel Cleaning, were not adequately supported. As shown in Exhibit A-83, the total test year expense associated with these two projects is $366,000. [Consumers' witness] Mr. Hugo presented direct testimony explaining major maintenance expense at 6 Tr 2042 and described projects planned for the Campbell units at 6 Tr 2047-2048. In his rebuttal, Mr. Hugo characterized the major maintenance projects as routine, with costs based on historical experience. [The] MEC [Coalition] disputes that the projects are routine, arguing that one project in particular, the screenhouse and tunnel cleaning, is performed only sporadically.

PFD, pp. 289-290 (footnotes omitted).

Referring to the Landfill-Clean Dry Ash Silo and Screenhouse and Tunnel Cleaning, the ALJ found that "Consumers has adequately supported the planned major maintenance projects for the units. Because these are not capital projects, they do not require the same degree of engineering and procurement, and are less likely to be delayed." *Id.*, p. 290.

Consumers' and the MEC Coalition's arguments related to avoidable maintenance costs projected for Campbell units 1 and 2 have been reviewed and considered and the Commission finds the ALJ's recommended reduction of $672,000 in avoidable maintenance costs projected for the units (discussed earlier in this order) to be reasonable and supported in the record. As discussed earlier in this order, the avoidable maintenance costs are to be foregone until Consumers' upcoming 2021 IRP in which the retirement of the units will be evaluated. Therefore, the Commission adopts the O&M reduction of $672,000.

However, the Commission is not persuaded that the MEC Coalition's suggested reduction of $366,000 for the Landfill-Clean Dry Ash Silo and Screenhouse and Tunnel Cleaning is appropriate. The Commission agrees with the ALJ that Consumers adequately supported its projections and plans and that the plans are less likely to be delayed than some other projects. Therefore, the Commission rejects the suggested $366,000 reduction related to Landfill-Clean Dry Ash Silo and Screenhouse and Tunnel Cleaning.

b. Attorney General's Adjustments

The ALJ stated in her PFD that:

> [The Attorney General] recommended a $6.4 million reduction to the expense for this line item, presenting an analysis in Exhibit AG-1.57 to show a slightly downward trend in spending in this category once the costs for major maintenance projects and for the Karn Separation and Retention are separated. [The Attorney General] recommended that the 2017-2019 three-year average of the expenses thus adjusted be used, with the major maintenance and Karn Separation and Retention costs added back, resulting in a projected expense for this category of $160.4 million. Although not directly addressing the Attorney General's analysis in rebuttal or in its initial brief, Consumers objects to the Attorney General's recommendation as without merit, citing [Consumers' witness] Mr. Hugo's direct testimony in support of the base O&M costs. The company also argues that the company's projection results in annual increase in base O&M expense of only 1.6%, and an annual decrease in environmental expense of 2.6%. Consumers also argues that the company's expenses averaged over a longer period would have been significantly higher, citing the historical data in Exhibit AG-1.57.9.

PFD, pp. 290-291 (footnotes omitted).

The ALJ found that Consumers' projections were reasonable, considering the work that must be done during outages and, accordingly, recommended that the Attorney General's suggested reductions be rejected. PFD, p. 291.

The Attorney General takes exception, stating that:

> [The Attorney General's witness] Mr. Coppola first segregated Major Maintenance expense and the 2019 expense related to the Karn Separation and Retention Payments from the other expenses. Exhibit AG-1.57, shows the trend in expense from 2014 to 2019. Other expenses on line 3 [have] trended lower since 2014 with some variation up and down. These expenses were $142.2 million in 2014 and have declined to $113.9 million in 2017, $120.4 million in 2018 and $109.2 million in 2019. Mr. Coppola used the average cost level for the three years 2017 to 2019 is an appropriate starting point. The average cost level for the three years is $114.5 million, as shown in column (h) of Exhibit AG1.57. Mr. Coppola added $3.2 million to reflect inflation and also the estimated costs for major maintenance, and the Karn Separation and Retention Payments to this amount. The result is a reasonable forecast of $160.4 million, as shown on line 10 of the exhibit. Company witness Hugo started with the expense amount from the 2018 historical test year to build his projected test year expense. It is also the highest expense level over the last few years as indicated above, while Mr. Coppola used an average expense level from 2017 to 2019 which is $114.5 million and consistent with the trends for this expense over the last several years. Mr. Coppola's forecast of $160.4 million is

> more representative of how costs have trended and a reasonable forecast of this O&M expense for the projected test year. Mr. Coppola provided a reasoned approach given where the costs for this category of expenditures has trended, while the Company's approach maximizes the cost. As the PFD notes, the Company never rebutted his approach. More importantly, Consumers failed to meet its burden to prove that its cost estimate is fair and reasonable to ratepayers.

Attorney General's exceptions, pp. 35-36 (footnotes omitted).

Consumers replies to the Attorney General's exceptions that it had no need to rebut the Attorney General's proposed three-year approach to base general O&M spending because the company's witness provided adequate testimony that Consumers' methodology was appropriate. Consumers rejects the Attorney General's proposed three-year average O&M calculation as simplistic, uninformed, arbitrary, and argues that its use will result in a projection that is less than actual recent generation O&M expense levels. Consumers' replies to exceptions, pp. 57-59. Consumers reiterates its extensive testimony in support of its projections on this issue and argues that the Commission should reject the Attorney General's proposed calculations and reductions as being unsupported. *Id.*, p. 59.

The Commission has reviewed and considered Consumers' and the Attorney General's arguments, as well as the ALJ's analysis and recommendations, and is not persuaded that the Attorney General's reductions to this line item are appropriate. The Commission further finds that the ALJ's recommendation that the Commission accept Consumers' projection of $167 million less $7.4 million for the Karn Retention and Separation Plan is reasonable and supported in the record and, therefore, is adopted by the Commission.

5. Customer Experience

Several adjustments related to this category and the ALJ's recommendations to the Commission regarding those adjustments are discussed earlier in this order.[22] In discussing customer experience projections, the ALJ again stated her recommendation that, for reasons previously set forth, the Staff's suggested $2.17 million reduction to exclude Consumers' unsupported inflation calculation was reasonable and should be adopted. The ALJ also noted her earlier acceptance of the Staff's suggested reductions of $44,625 for the AAH and $266,296 for the CRM.[23] PFD, p. 291.

The ALJ went on to discuss the Staff's concerns related to Consumers' customer payment program, particularly Consumers' projection of increased costs related to credit card payments from $4.5 million in 2017 to $7.0 million in 2021. The Staff testified that, in 2018, only 36% of Consumers' customers paid their power bills electronically; however, Consumers projected a 47% increase in related costs for 2023. The Staff voiced further concerns that Consumers cannot provide auditable transaction costs related to electronic payments because the company does not track them, to which Consumers responded that its projections are reasonably based on its actual 2019 expenses plus forecasted growth. The Staff recommended that Consumers should provide greater detail on these transactions, separated by customer class, to support its projections for electronic payments costs. PFD, pp. 291-293.

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[22] In earlier discussions set forth in this order, the Commission adopted the following changes and reductions to Consumers' projections as recommended by the ALJ: rejection of the bifurcation of labor and nonlabor inflation rates and rejection of the use of Consumers' proposed inflation rate for labor (*See*, Section IV.C.1. of the PFD); exclusion of a $2.17 million O&M inflation projection set forth in Exhibit A-75 (*See*, Section IV.2. of the PFD); and O&M expense reductions of $44,625 and $266,296 for the AAH and CRM, respectively (*See*, Section IV.A.8. of the PFD). PFD, p. 291.

[23] The ALJ discussed these matters in Section IV.A.8. of her PFD.

The Staff expressed its concerns about Consumers' inclusion of invalid third-party activity costs in its projection, i.e. payments made by a third-party consolidator via credit card that are processed by a third-party vendor with which the company has contracted for this service. The Staff asserted that the terms and conditions on Consumers' website prohibit payments from consolidators. The Staff recommended that $238,248~~,000~~ be excluded from Consumers' projections for these costs; to which Consumers responded that such costs are inherent in the payment processing industry and an unavoidable expense. *Id.*, pp. 292-293.

Further, the Staff indicated that the Commission likely did not intend to socialize costs into its rates other than the fees related to customer payments made via credit/debit card[24] and suggests that a three-year average of actual costs from the vendor that processes the credit/debit card payments is a more accurate manner with which to account for the associated fees that are socialized to ratepayers. The Staff suggested a downward adjustment of $2.074 million to Consumers' projection of $10.4 million for these costs. *Id.*, p. 293.

The Staff also recommended a $1,913,000 downward adjustment to remove the fees for authorized pay stations. The Staff agreed to Consumers' compromise to lower the amount to $442,170 based on a projected decline in customers use of authorized pay stations in the test year.

The ALJ found that the following downward adjustments should be adopted: (1) $238,248 for invalid third-party activity costs and (2) $2.074 million for credit/debit card vendor fees. PFD, p. 94. She stated her agreement with the Staff that customers are not aware of these third-party costs and should not be responsible for covering them. The ALJ further stated that she agreed with the Staff that the Commission intended (in the July 31 order) to socialize only actual credit card

[24] The Staff referred to the July 31, 2017 order in Case No. U-18124 (July 31 order), pp. 70-71, which permitted inclusion of costs in rates for recurring credit card payments, small business customer payments, online payments, and payments made at direct pay offices.

fees. Finally, the ALJ stated that Consumers' projection lacked sufficient information to determine the validity of its $7.0 million projection for increased O&M costs for credit card payments, and thus she found ~~that~~ the Staff's three-year average of actual historical costs to be reasonable.

Consumers excepts, arguing that the PFD incorrectly recommends a reduction in its labor inflation figure for customer service due to lack of support. Consumers reiterates its arguments that its labor inflation rate should not be tied to the CPI and is necessary to provide merit increases to its employees. Consumers argues that the Staff has not properly included the inflation rate in its projections and the correct reduction, at a minimum, should be $591,000 rather than $2.166 million as proposed by the Staff. Consumers' exceptions, pp. 160-161.

Consumers also excepts to the ALJ's adoption of a three-year average of actual costs for credit/debit card expenses and asserts that credit/debit card expenses cannot be based on past expenses because their use and associated costs are expected to increase. *Id.*, pp. 160-162.

Additionally, Consumers excepts to the ALJ's agreement that expenses related to invalid third-party activity should be reduced and states that customers' lack of awareness of the costs does not render them to be inappropriate or unrecoverable. Consumers reiterates its testimony related to these issues in the record. *Id.*, p. 162.

Finally, Consumers excepts to the ALJ's recommended adjustments to the AAH and CRM for reasons discussed on page 121 of its exceptions. *Id.*, p. 163. The positions of the parties and the Commissions' decision on these matters are discussed earlier in this order and the Commission rejects these expenses as being more appropriately included in Consumers' 2021 IRP.

The Commission has examined and considered the positions of the parties on the matters set forth in this section, above, as well as the analysis and recommendations of the ALJ, and finds

Consumers arguments to be unpersuasive. Further, the Commission finds the ALJ's analysis to be well reasoned and supported in the record and, therefore, the Commission adopts the ALJ's recommendation that a reduction of $238,248 for invalid third-party activity costs, and a reduction of $2.074 million for credit/debit card vendor fees should be applied to Consumers' projections.

6. Corporate Services

The Attorney General and the Staff proposed downward adjustments to this category in addition to the $1.314 million inflation-related revisions discussed in Section V.C.1 of this order, above.

The Attorney General proposed a general reduction of $5.9 million based on a three-year historical average and the premise that annual expenses are variable.[25] Consumers opposed the reductions and argued that corporate services expenses are fairly stable from year to year. PFD, pp. 294-295.

The ALJ discussed the Staff's concern regarding insurance rebates and Consumers' response:

> [The] Staff instead takes issue with the company's normalization of certain insurance rebates. [The Staff's witness] Mr. Welke testified that the company regularly receives insurance refunds, and explained that those refunds are included on line 2 of Exhibit A-62, "General Counsel, Legal and Risk Management." These are the refunds that [Consumers' witness] Ms. Gaston listed for 2018 in her testimony at 6 Tr 1835 and for 2019 in Exhibit A-164. Mr. Welke explained that Consumers recommends projecting these refunds using a five-year average from 2014 through 2018, which results in a reduction to expenses of $4,867,593. He testified that Staff recommends using a three-year average, based on the 2017 through 2019 refund amounts, which results in a reduction to expenses of $7,758,000. He explained that this three-year period was reasonable in light of the three-year difference between the projected test year in the company's last rate case and the projected test year in this case. He testified that the resulting adjustment to the company's projection is a reduction of $2,890,407, but noted that after he prepared his testimony, Consumers revised the figures Staff relied on, which are not included in Staff's adjustment. In its brief, Staff recalculates the adjustment as $2,426,000 based on the company's updated insurance refund figures. Staff cites the Commission's order in a Consumers electric rate case, Case No. U-16191, as

[25] *See*, Exhibits AG-1.60 and A-62.

> approving a three-year average, while acknowledging that it has approved five-year averages in several cases, citing an order in a Consumers gas rate case, Case No. U-17735.
>
> Consumers objects to Staff's recommendation to use a three-year average of refunds and credits. It cites Ms. Gaston's rebuttal testimony that "refunds are based on activity in the insurance markets and can be extremely volatile with high refunds in one year, to low or possibly no refunds in the next year." She presented Exhibit A-164 to show this volatility. As Ms. Gaston explained in her rebuttal, Consumers does not object to updating the five-year average to include 2019 refunds and credits, if its projected expense for this category is also updated to reflect 2019 actual expenditures. She presented a calculation in Exhibit A-165 to calculate the revised 2021 projection based on 2019 actual data with inflation for the years 2020 and 2021. She testified based on this exhibit that if 2019 actuals are used, the 2021 expense projection would increase by $1,586,000, while the offsetting insurance refund adjustment based on a revised five-year average would increase by $1,048,000 as shown in her Exhibit A-164.

PFD, pp. 295-296 (footnotes omitted).

The ALJ was troubled by Consumers' presentation and stated:

> This PFD finds the company's presentation extremely troubling. Beginning with the Attorney General's proposal, the difficulty with this proposal is that it appears Mr. Coppola's recommendation reflects the variability in certain insurance refunds that Consumers has comingled with other expenses in line 2 of Exhibit A-62. As noted above and as stated in the company's discovery response in Exhibit S-9.1, Consumers' 2018 actual expenses for the General Counsel, Legal and Risk Management category on line 2 of Exhibit A-62, in the total and non-labor columns (c) and (d), reflect $10,852,439 in refunds and credits from three sources; these are itemized in Ms. Gaston's testimony at 6 Tr 1835, which also shows the calculation of the five-year average over the period 2014- 2018. Ms. Gaston testified regarding Exhibit A-62: "Specific line item changes are included as increases or decreases as appropriate to reflect exclusions, remove one-time costs, reflect transfers of costs into or out of the Corporate Services area, or reflect significant ongoing changes in Corporate services O&M expense." Indeed, several adjustments are shown as line-item changes in this exhibit, including a $625,000 adjustment to exclude corporate giving and lobbying expenditures. However, as Exhibit S-9.1 makes clear, buried in what looks like a straightforward spreadsheet applying inflation factors to successive columns is the company's adjustment for insurance refunds and credits; this is accomplished in that spreadsheet in row 2 by simply adding the approximately $6 million difference between the five-year average refund ($4,867,593) and the refund included in the 2018 actual value ($10,852,439) to the spreadsheet entry for the 2021 non-labor projected value in column (l). Not only is there no separate line item to incorporate this adjustment, there is not even a footnote. What purports to be a column multiplying the number in column (i) by the inflation rate 1.023 is in reality that multiplication plus $6 million.

This is not "transparent" and it is not proper. The Commission and the parties have the right to expect that figures presented in a spreadsheet will follow the stated spreadsheet formulas without the need for them to check the arithmetic underlying all the entries. As discussed above, this reinforces Staff's recommendation that the Commission demand greater transparency from Consumers in presenting cost projections.

Nonetheless, because the "actual" expenses Consumers reported contain actual refund amounts, not adjusted, from year to year but only adjusted for the year 2021, a review of Mr. Coppola's calculations in Exhibit AG-1.60 show that the annual costs he worked with must contain these variable refund amounts. Since no specific adjustment is stated, it appears the 2019 actuals he used included an offsetting refund of approximately $7 million. For this reason, this PFD does not recommend accepting this adjustment.

Turning next to Consumers' claim that using 2019 actual expenses for this category would result in a higher cost projection, a review of the company's presentation shows this claim is based on its deceptive treatment of the insurance credits and refunds in [the company's] exhibits, as well as the confusing interplay of other adjustments. Consumers reported 2019 expenses for this category on line 13968 of Exhibit A-165, column (g), as $54.4 million, prior to the adjustments on subsequent lines. In contending that an additional $1.6 million should be added to the company's test year expense projection, Consumers compares this $54.4 million to what it labels as its projected 2019 expense of $52.8 million on line 13, column (g) of Exhibit A-62. This comparison is not accurate because these lines reflect differing amounts of insurance refunds and credits, and Consumers' final projected expense for 2019 also includes a projected level of excluded EICP expense (line 14 of Exhibit A-62) that proved to be an understatement (line 14 of Exhibit A-165), as well as accounting for insurance premiums that were paid in 2018 (line 19 of Exhibit A-62), but not in 2019. Because Consumers made no effort to account for these differences, its claims regarding 2019 should be dismissed without further analysis.

Nonetheless, to properly compare the company's 2019 estimate to the 2019 actuals, it should be noted that Consumers' 2019 estimate presumes the $10.9 million in credits and refunds will continue from 2018, plus inflation at 2% for a total of $11.1 million, while 2019 actuals contain a refund of $7.2 million; if Consumers properly accounted for this $3.9 million difference, it would raise the 2019 projection to $56.7 million for comparison purposes. Additionally, the 2019 projection forecast excludable EICP payments of $3.1 million, while the 2019 actual expense included $4.8 million; had that increase been properly forecast, Consumers 2019 forecast would have increased by $1.7 million before the exclusion of those EICP payments, equivalent to a $58.3 million projection. Finally, because Consumers ceased paying certain insurance premiums in 2018, its 2019 forecast was adjusted to reflect that cessation; subtracting the $3.3 million storm insurance premium from the forecast (as Consumers does on a subsequent line of Exhibit A-62) is necessary for a proper comparison to 2019 actuals, making

> the company's 2019 forecast for comparison purposes $55 million. Thus, putting the 2019 forecast on a basis comparable to the reported 2019 actual expense shows that 2019 actuals were not in fact higher than projected, but approximately $0.6 million less, once the differences in refunds, EICP payments, and insurance premiums are taken into account.
>
> Also as noted above, there are other troubling aspects of the company's presentation in Exhibit A-62 and subsequent iterations in Exhibits A-163 and A-165. Because the normalizing adjustments to 2018 are made in lines 14-22, and carried forward without an inflationary adjustment, the 2021 projection will include inflation on those base items that are not going to be actual expenses in the projected test year. While the amount of distortion is relatively small, given Staff's concern with transparency, this approach should be discouraged in future filings.
>
> This PFD further finds that it is appropriate to update the adjustment for the insurance refunds and credits to include the 2019 value, and to adopt Staff's recommended three-year average for this category. While Ms. Gaston presented Exhibit A-164 to show historic [sic] variability, she only presented the 2014 through 2019 data, and made no effort to account for the significant increases in the recent two years. This PFD finds Mr. Welke's testimony persuasive on this point.
>
> In summary, this PFD finds that Staff's incorporation of the 2019 insurance refund amount and its use of a three-year average is appropriate, resulting in an additional reduction of $2,426,000, while Consumers has failed to establish that appropriately using the 2019 actual data in a revised projection would lead to an increased expense projection for 2020.

*Id.*, pp. 296-300 (footnotes omitted).

Consumers takes exception to the ALJ's findings and recommendations and disputes her conclusion that it did not make an effort to account for recent significant increases in insurance refunds. Consumers argues that the company provided ample explanation in its presentation that insurance refunds are volatile and may be very high one year and possibly nothing the next year. The company restates its figures set forth in Exhibit A-164 that show insurance refunds at a low of $3.3 million in 2014 and a high of $10.9 million in 2018. The company argues that its five-year average better accounts for this volatility compared to the Staff's three-year average. Consumers points out that the Staff has suggested the use of five-year averages to project other expenses such as service restoration expenses and IT O&M expenses. Further, Consumers argues that the

Commission approved a projection based on a five-year average of insurance premiums net of insurance refunds, credits, and distribution in Case No. U-17735[26] and the company has used a five-year average projection for significant insurance refunds in Case Nos. U-17990, U-18322, and U-20134. Consumers' exceptions, pp. 163-164.

Further, Consumers denies that its insurance refund projection is not transparent or is improper. The company states that it is open to suggestions that will enhance clarity in its rate case presentations, but asserts that its corporate services expense projection would increase by $1,586,000 if actual 2019 expenses were used and, after a downward adjustment for the $1.048 million related to the updated insurance refund, its updated expense projection would increase by $514,000 over its initial projection. *Id.*, pp. 165-166.

The Attorney General excepts to the ALJ's recommendation to reject her suggested $5.9 million reduction to the corporate services O&M projection and argues:

> Exhibit A-62 (KMG-2) shows that the Company developed the projected test year forecast by escalating the 2018 labor costs by 3.2% annually and increasing the 2018 non-labor costs by rates of 1.5% to 2.3% annually from 2019 to 2021. The Company also made some normalizing adjustments to 2018 reported expense. The historical corporate expense in the most recent five years from 2015 to 2019 has ranged from $45.5 million to $56.9 million with the low end of this range occurring in 2018. The average expense over the three-year period has been $49.5 million which is slightly lower than 2019 actual costs.
>
> The $2.4 million adjustment proposed by Staff and adopted by the PFD pertains only to the normalization of insurance refunds over three years as calculated by Staff instead of five years as proposed by the Company. The Attorney General's proposed disallowance of $5.9 million goes further and includes other cost increases that the Company did not explain or justify. Lines 6 through 10 of Exhibit AG-1.60 show that the five-year historical average of Corporate Expenses adjusted for inflation to the end of the test year are $50.9 million. On lines 1-4, the Attorney General shows the Company's proposed expenses for the test year

[26] In the November 19 order, the Staff recommended a downward insurance adjustment based on a "five-year average of insurance premiums net of refunds, credits, and distributions," and stated that because insurance premiums do not seem to be trending upwards, using a five-year average provides the most appropriate expense." November 19 order, p. 67.

> normalized to remove insurance proceeds and other items for a test year forecast of $56.8 million. The difference between these two amounts is $5.9 million which takes into consideration insurance refund adjustments and other cost increases not supported or justified by the Company.

Attorney General's exceptions, pp. 38-39 (footnotes omitted).

The Commission has considered and reviewed the positions of the parties, as well as the ALJ's analysis and recommendations. While the Commission may have approved use of a five-year average for corporate services projections in the past, the Commission agrees in this case with the ALJ that Consumers' five-year projection lacks transparency. The Commission also finds that Consumers did not satisfactorily address the ALJ's concern about the projected insurance refunds in its exceptions. Further, the Commission finds the Staff's projection, based on a three-year average that included 2019, to be clearly explained and supported in the record.

Additionally, the Commission has concerns about Consumers' handling of storm restoration insurance expenses and the deduction of the annual storm restoration insurance premium that Consumers no longer pays. These matters are not sufficiently explained and reconciled in the record or addressed in exceptions. The Commission expects that, in future filings, Consumers will clearly address these concerns with supported and consistent expense projections related to these matters.

The Commission is not persuaded that the Attorney General's argument that a $5.9 million reduction in Consumers' corporate services projection is warranted and neither is the Commission persuaded that the Attorney General's calculation is appropriate (*see*, the ALJ's reasoning, above). While the Commission agrees that the company's projection lacks transparency, the Commission disagrees that the projected expenses, other than in the category of insurance refunds, are insufficiently supported so as to justify their exclusion from the projection. However, Consumers is forewarned that, in future filings, the company shall provide clear and auditable figures and explanations to support its projections.

The Commission finds that the ALJ's analysis and recommendations are well reasoned and supported in the record. Accordingly, the Commission adopts the ALJ's recommended reduction of $2,426,000, in addition to the inflation-related adjustments discussed earlier, to Consumers' projections for corporate services.

7. Information Technology

The PFD indicated that Consumers projected electric IT operations O&M expenses of $48,440,000 for 2020 and $49,287,000 for 2021[27] and projected $21,884,000 for IT investment O&M, including $978,000 for investment planning. PFD, p. 300.

The ALJ indicated that she addressed and accepted the following adjustments, discussed earlier in the PFD: (1) the exclusion of $123,000 in O&M expense for the centralized DR management project; (2) the exclusion of $1,247,029 in O&M expense for the application and currency enhancement projects discussed in Section IV.A.6.f. of the PFD; (3) the exclusion of $164,000 in projected O&M dashboard redesign expense discussed in Section IV.A.6.g. of the PFD; and (4) the exclusion of $434,445 projected O&M expense for the website redesign project, also discussed in Section IV.A.6.g. of the PFD. *Id.*, pp. 300-301.

In addition to the above matters, the ALJ stated that the Staff recommended an $11,357,000 reduction to IT operations O&M based on a five-year average of costs, and a $978,000 reduction to the investment planning portion of IT investment O&M expense. She noted the Staff's argument that the Commission had disallowed investment planning expense previously, finding it

[27] These figures are 11.1% and 13.1% greater than the 2019 expense, respectively. PFD, p. 300.

to be "speculative and contingent on moving forward with a project[,]" to which Consumers responded that investment planning is a necessary activity to ensure that investments provide value. *Id.*, p. 301. The ALJ also noted the Staff's argument that, historically, the Commission has found that a five-year average for the projection of IT operations expense is reasonable and that a five-year average methodology prevents projections that may be unpredictable and speculative. *Id.*, pp. 301-302. Consumers' conceded that if any adjustments to IT operations were to be made, the 2018 historical spend of $46 million plus inflation would be appropriate. *Id.*

The ALJ stated that the Commission has previously determined that a projection based on a five-year average is reasonable for IT O&M operations expense and that the Commission has also found, in previous orders, that IT O&M investment planning expense should be disallowed. She reasoned that Consumers did not provide a compelling reason to change the Commission's preference for the use of a five-year average methodology. The ALJ also found that the IT O&M expenses set forth in Exhibit S-14.0 show an increase in expenses but are not auditable because they are all projected figures. The ALJ thus adopted the Staff's recommended $11,357,000 reduction for overall IT O&M expenses as a result of the application of a five-year average methodology to the projection and $978,000 reduction to eliminate investment planning. *Id.*, pp. 304-305.

Consumers excepts to the ALJ's recommendations and argues that the Commission should approve all test year IT O&M expenses and reject the Staff's five-year average methodology, in favor of Consumers' methodology, or in the alternative, in favor of the recent year actuals methodology. First, Consumers argues that all IT operations expenses are necessary to provide reliable, secure operations and include, among other items, system monitoring, maintenance, application upgrades, and security improvements, the lack of which will result in poor customer service. Second, Consumers argues that almost half of its IT and security operations expenses are in committed contracts with vendors that will provide many of the necessary services mentioned above. Consumers reiterates its testimony provided in the record regarding the types of necessary operations the company performs to provide system stability and security for its ratepayers. Further, the company points out that a five-year average methodology has not been used in all recent cases, citing Case No. U-18322. Additionally, Consumers argues that looking at five-year historical expenses cannot be employed to accurately project future expenses because the company is increasing its use of technology at a rapid rate which results in future increased costs. Consumers exceptions, pp. 169-174.

The Commission is not persuaded by Consumers' argument that it is unreasonable to base its IT projection on a five-year historical average because the company's rapidly increasing reliance on technology will result in rapidly increasing IT expenses. The company provided few specifics regarding its IT plans for the future or how its processes will be affected by those plans. The Commission is not opposed to increased reliance and spending on IT because it has proven to be a pathway to improved customer service and satisfaction in the past, but the Commission is currently not persuaded that it is reasonable or prudent to approve a projection that includes expenses that are greater than that achieved by basing the projection on a five-year average. The Commission notes that Consumers is in the process of developing an IT plan and encourages the company to include specifics of its planned purchases and other expenses that are based on actual anticipated costs. The Commission finds that a projection based on a five-year historical average is appropriate at this time considering that Consumers' presentation lacked a specific, detailed plan for the future; however, the Commission is flexible on the time frame employed for projections in future filings if a supportable, concrete IT plan accompanies the projection and a different timeframe appears to be warranted.

Further, the Commission is not persuaded that investment planning benefits ratepayers to the extent that recovery from ratepayers should be permitted. The Commission has historically rejected projections for investment planning and Consumers has not provided sufficient reason to support a change in direction on the issue.

The Commission finds the ALJ's analysis and recommendations related to Consumers' IT projections to be well reasoned and supported in the record. For these reasons and those discussed above, the Commission adopts the ALJ's recommended reduction of $11,357,000 to Consumers' IT projection and her recommended reduction of $978,000 to the investment planning portion of IT investment O&M.

8. Pension and Benefits

The Attorney General argued that Consumers' projected 14% increase in active health care expense was excessive and, accordingly, proposed a $1 million downward adjustment for these costs. The Attorney General presented an analysis of historical active health care costs and argued that a 2.5% increase was appropriate considering the rate of increases in historical costs. Consumers' objected to the reductions and stated that one cannot look solely to historical costs but must look forward to expected costs. The ALJ was not persuaded by Consumers' arguments and adopted the Attorney General's reduction. PFD, pp. 304-305. She stated that the company did not satisfactorily explain why costs that were relatively flat in the past were expected to increase so steeply and that the company had not rebutted the Attorney General's assertion that Consumers consistently over-projected active health care costs.

Consumers excepts to the ALJ's recommended $1 million reduction in active health care costs and further argues that the Attorney General stated no basis for her assertion that Consumers has consistently overstated its projections. Consumers also argues that there is ample support in the record to support its projection and reiterates its related testimony and exhibits. Additionally, Consumers points to its reliance on a comprehensive and forward-looking study in preparing its projection. Consumers' exceptions, p. 185.

The Commission has reviewed and considered the positions of the parties and is not persuaded that Consumers' original projection is appropriate. Further, the Commission finds the ALJ's analysis and recommendation to be well reasoned and supported in the record, regardless of whether Consumers has consistently over-projected active health care costs in the past. Accordingly, the Commission adopts the ALJ's recommended $1 million reduction in Consumers' active health care costs (inclusive of various life insurance and long-term disability expenses).

9. Employee Incentive Compensation Plan

Consumers requested recovery of $5.2 million for its employee incentive compensation plan (EICP) but, acknowledging the Commission's previous rejection of recovery of incentives based on financial metrics, offered a compromise of 50/50 sharing of that portion of the costs. The company asserted that costs that are tied to financial incentives benefit the company's credit rating. Consumers further stated that EICP payouts have resulted in savings due to fewer safety incidents, as well as savings for increased distribution reliability, among other benefits that affect customer service and satisfaction. PFD, pp. 305-307.

The Staff argued that the EICP projection should be reduced by $3.4 million or more and that the $1.2 million in bonuses should be excluded. The Staff argued that the Commission has historically rejected expense projections that are tied to achievement of financial goals and qualified its recommended partial inclusion of financially related incentives as being consistent with prior Commission orders. However, the Staff objected to even partial inclusion, in principle, "because the 'market-median' level of payout can be made under the program if only financial measures, and no operational measures, are attained[]" and because '"[i]t's not reasonable that an opportunity to earn 'market-median' pay exists after falling short of safety and reliability priorities."' *Id.*, pp. 307-308. The Staff further stated that two of Consumers' exhibits presented in support of the EICP lacked source references and one was duplicative of a previous exhibit. *Id.*

The Attorney General argued that EICP recovery should be rejected in its entirety because, for non-officers, the company has relaxed some of the financial incentives tied to program payouts and because payout ratios have exceeded 100% since 2011. She stated that, for officers, bonuses are almost entirely based on earnings per share and operating cash flow. *Id.*, p. 308. The Attorney General also argued that performance measures are too heavily weighted toward "financial performance metrics that do not directly benefit customers." *Id.*

In rebuttal, Consumers argued that the EICP must have achievable goals or employees will not be motivated, and that benefits to customers exceed $5.2 million. *Id.*, 310.

The ALJ was persuaded by the Attorney General's presentation that Consumers' full EICP projection should be rejected, and stated:

> First, Consumers' EICP payout criteria [are] far too heavily weighted to financial performance rather than achieving operational objectives. The Commission has rejected the company's claim that financial measures benefit ratepayers. And while [Consumers' witness] Mr. Wehner ascribes an $88 million benefit due to the company's credit rating, this PFD notes that ratepayers pay a substantial amount in rates to cover the company's debt costs and provide a return on equity. For example, this PFD includes $663 million for the 2021 test year as shown in Appendix A. Second, despite a history of EICP payments, in some cases at more than 100%, Consumers' performance with respect to reliability and safety continue to decline, as Mr. Coppola's testimony illustrates. Finally, as [the Staff's witness] Mr. Welke testified, the EICP is structured so that employees can receive

> market-based pay without meeting any operational objectives at all. Therefore, the company's requested $5.2 million for EICP should be rejected.

*Id.*, p. 311.

Consumers' excepts to the ALJ's recommendation that its entire EICP projection be rejected and argues that, historically, the Commission has allowed, at least, the inclusion of EICP costs that are tied to operational goals.[28] As well, Consumers points out, that in its decision in Case No. U-17335,[29] "the Commission recognized that at least the portion of the Company's EICP incentive based on operational goals yields customer benefits and is appropriate for inclusion in calculating rates." Consumers' exceptions, p. 186. Further, Consumers asserts that EICP payouts focus on goals that relate to public and employee safety, cost, reliability, delivery, and customer care, reiterates its supporting testimony in the record, and argues that if the company did not maintain strong financial results, ratepayers would be responsible for an additional $7 million annually in rates to cover Consumers' debt costs.[30] Consumers continues that EICP payouts, at least in part, have resulted in the elimination of that $7 million in debt costs. Consumers' exceptions, pp. 186-188. Consumers reiterates its presentation in the record that "the operational goals also have quantifiable benefits to customers in excess of $24 million annually resulting from just two of the Company's nine operational goals[,]" and denies the ALJ's statement that Consumers' safety and reliability performance has declined. *Id.*, p. 188. Consumers also denies

[28] Consumers cites the February 28 order, p. 106; the July 31 order, p. 87; and the March 29 order, p. 67. Consumers' exceptions, p. 186.

[29] Refers to the November 19 order, pp. 77-78.

[30] Consumers asserts that its credit rating was BBB- in 2006 but had increased to A by 2014 and that the company has achieved an A rating each year since 2014. Consumers calculates the asserted $7 million annual saving to ratepayers by averaging the company's annual interest savings of $88 million for years 2006 through 2019. Consumers' exceptions, p. 187; Exhibit A-14, Schedules D-3 and D-5, p. 7.

that it paid EICP to its nonofficers at a rate of 100%, stating, first, it is mathematically impossible, and second, that without the EICP payouts, its employee compensation would be below market competitive levels. *Id.*, pp. 190-191.

The Attorney General replies that Consumers' exceptions are invalid because each case is considered by the Commission on its own merits, rather than precedent, and that the question is whether ratepayers should fund company employees' incentive bonuses. The Attorney General argues that savings to ratepayers based on the company's good financial standing are illusory and that the company has an obligation to manage its business in a prudent manner. Further, the Attorney General notes that the record includes testimony that there have been recent declines in safety and reliability goals, effectively refuting Consumers' argument that EICP payouts have improved these metrics. Additionally, the Attorney General reiterates its argument that non-officer EICP measures for payout are vague and general and officers are effectively guaranteed to receive their EICP payments if financial measures are met, regardless of whether the company achieves or fails to achieve its performance objectives. Finally, the Attorney General argues that Consumers failed to establish a direct cause and effect between the cost of the EICP payouts and a commensurate financial benefit to ratepayers. Attorney General's replies to exceptions, pp. 50-53.

The Commission has reviewed and considered the arguments of the parties and concludes that any portion of Consumers' projection for EICP that is tied to the achievement of financial goals should be excluded because Consumers has not satisfactorily established that ratepayers receive a benefit that is commensurate with and directly related to the cost of that portion of the program or that it rewards specific, measurable achievements that benefit ratepayers. The record, in this case, demonstrates that EICP payouts that are tied to financial measures predominantly benefit shareholders, with benefits to ratepayers being tangential and comparatively nominal. Further, the

Commission finds that Consumers' alternative proposal (inclusion of 50% of EICP expense related to financial metrics) is not appropriate because the record does not support that half of the incentive compensation costs to be recovered in rates provide a commensurate benefit to ratepayers. Thus, ratepayers should not be responsible for these costs. Accordingly, the Commission rejects the recovery of any funds related to the achievement of financial metrics.

However, the Commission is persuaded that EICP payouts that reward specific, measurable achievements related to operations are reasonable and prudent, given the focus on improved safety, reliability, customer service, and other metrics more directly benefitting ratepayers. The recovery of these EICP amounts for operational metrics is also consistent with past precedent since 2015. Going forward, the Commission is interested in a more thorough examination of compensation and the design and application of specific performance metrics to ensure this approach remains reasonable and prudent. Accordingly, the Commission finds that $1.762 million should be included for this line item.

10. Outstanding Contributor/New Employee Signing Bonus

Consumers asked for recovery of the $3,000 signing bonuses paid to new employees, as well as the $3,000 bonuses paid to current employees who make outstanding contributions to the company which, in turn, have a positive effect on customer service and satisfaction. Consumers asserted that these payments are intended to attract and retain high performing, talented personnel. The Staff voiced its opposition to the bonuses, arguing that they are discretionary, based on vague criteria, and that paying bonuses during the current economic climate may not be good public policy. PFD, pp. 311-312.

The ALJ adopted the Staff's suggested $1.23 million exclusion for the bonuses as being reasonable. She explained that the company cited no Commission order to support employee bonuses, agreed with the Staff that the program was vague and discretionary, and also asserted that Consumers had not established that this type of award program should be funded by ratepayers. *Id.*, p. 312.

Consumers excepts to the exclusion of recovery for outstanding contributor and signing bonuses and reiterates that attracting and retaining outstanding employees is a benefit to ratepayers. The company further argues that the bonuses are reasonable because the Consumers has "established that employee recognition is important as it increases the level of productivity at work, reduces employee turnover, and increases customer satisfaction." Consumers' exceptions, p. 191. Consumers denies that its awards are vague, stating that its "Leaving It Better" program is awarded to employees who "impact the Company's success by exhibiting one or more of the Company's Guiding Principles, in a way that furthers the Company's strategy, operational excellence, customer satisfaction, and/or corporate reputation." *Id.*, pp. 191-192.

The Commission has considered and reviewed the parties' positions on the matter of employee bonuses and is not persuaded that these expenses should be funded by ratepayers. Further, the Commission finds the ALJ's recommendation on the matter to be well reasoned and, accordingly, adopts the ALJ's recommendation that $1.23 million projected for employee bonuses should be excluded.

11. Demand Response

The ALJ states in her PFD that Consumers projects test year O&M costs of $15,748,000 for its business DR and $18,933,000 for its residential DR program for a total of $34,681,000. The ALJ indicated that the Attorney General initially opposed Consumers' projections but withdrew her recommended disallowance in her initial brief. PFD, p. 313.

The Commission finds that the matter of Consumers' DR projections is unopposed by any party to the proceeding, is reasonable and prudent and, therefore, adopts Consumers' test year projection for this expense.

12. Uncollectible Expense

Consumers initially proposed test year uncollectible expenses of $18.1 million using the average of the bad debt loss ratio of cash basis uncollectible accounts expense for the years 2016 through 2018. The Attorney General updated the expense using the 2017-2019 timeframe and recommended a reduction in the projection of $1.2 million, with which Consumers agreed. PFD, p. 313.

The Commission finds that the matter of Consumers' uncollectible expense projection is unopposed by any party to the proceeding, is reasonable and prudent and, therefore, adopts the ALJ's recommendation for test year projections for this expense.

13. Electric Injuries and Damages

The Attorney General and the Staff recommended a reduction in the projection for electric injuries and damages from $4,531,000 to $3,785,000, a reduction of $746,000, with which Consumers agreed. The Commission finds that the adjusted projection for electric injuries and damages that the parties have settled on is reasonable and prudent and, accordingly, the Commission adopts the reduced projection of $3,785,000 for this line item.

D. Depreciation, Amortization Expense, Taxes, Allowance for Funds Used During Construction

According to the PFD, Consumers and the Staff agreed to a jurisdictional AFDUC amount of $6,203,000. The parties have reached an agreement on this line item and the Commission finds the agreed upon figure to be reasonable and prudent and, therefore, the Commission adopts the projection of $6,203,000.

Tax expense, depreciation, and amortization expense calculation methodologies were undisputed or drew no exceptions, and therefore those methodologies are approved, and the amounts are recalculated based on the decisions in this order.

## VI. OTHER REVENUE RELATED ISSUES

A. Financial Compensation Mechanism

In the June 7 order, the Commission approved a contested settlement agreement in Consumers' IRP proceeding. As a part of the settlement agreement, the Commission approved a financial compensation mechanism (FCM) on eligible power purchase agreements (PPAs) entered into after January 1, 2019. In the instant case, Consumers proposed an FCM amount of $3,031,000 for 2019 through 2021, to be recovered via a surcharge. The company further proposed to file a contested proceeding by March 31, 2022 to: (1) reconcile actual surcharge collections during 2021 to the actual FCM amount through 2021; and (2) establish the surcharge to be billed beginning July 1, 2022, designed to collect the 2022 FCM, as well as any difference between the actual surcharge billed during 2021 and the actual FCM amount through 2021. Consumers is opposed to including the FCM in a power supply cost recovery (PSCR) proceeding because, according to the company, PSCR proceedings do not have a statutory time limit and the FCM surcharges must be collected within 24 months of when they are recorded in order to record them in the period earned.

The Staff does not oppose the proposed FCM amount or the PPAs to which it would apply, but recommended that the timetable for reconciliation be expanded to 180 days or that the company should include the FCM in its PSCR proceeding as a standalone component. The Staff maintained that the company could avoid alternative revenue recognition if it waited to record the revenue until the FCM is approved. The Staff also recommended that if the company relies on projected sales to calculate the FCM, then carrying costs should be included using the same rates applied to PSCR over- and underrecoveries (e.g., the carrying cost on overrecoveries is set at the currently-approved ROE and the carrying cost on underrecoveries is the company's short-term debt rate).

Consumers opposed the Staff's carrying cost proposal arguing that rates for carrying charges are required to be applied to PSCR reconciliations only under MCL 460.6j. The company also requested that the Commission be explicit in approving either a 90-day or 180-day schedule for an FCM recovery proceeding so that the company is permitted to record FCM revenues in the period earned.

ABATE argued that the FCM is not an alternative revenue program and inclusion of the FCM in base rates is appropriate. ABATE also recommended that the FCM cost be allocated in proportion to the rate base that is allocated to each customer class, to which Consumers agreed.

RCG recommended that the Commission reject the FCM surcharge, arguing that the settlement agreement approved in the June 7 order did not state that the company could begin collecting an FCM immediately; rather, the June 7 order determined that the FCM mechanism or methodology to be utilized should be approved in this proceeding. RCG also agreed with the Staff that the FCM should be included in the PSCR case.

The ALJ found that the "Staff's proposal to file the FCM as a standalone part of the PSCR is reasonable." PFD, p. 319. She agreed that Consumers could wait to record the revenue until the FCM is approved. For carrying costs, the ALJ recommended that the Commission should apply the weighted average cost of capital (WACC) to any overrecoveries of FCM revenue and should apply the company's most recently approved short-term debt cost rate to any underrecoveries. *Id*. The ALJ also adopted ABATE's recommendation to allocate FCM costs in proportion to the allocation of rate base across customer classes, finding that the FCM is analogous to the return that Consumers receives on company-owned assets. *Id*., p. 385. The ALJ rejected the arguments by RCG and ABATE to include the FCM in base rates, explaining that, because Consumers may not file a rate case annually, recovery within 24 months may not occur. *Id*.

Consumers takes exception to the ALJ's recommendation to adopt the Staff's proposal to use carrying costs for over- or underrecoveries for the FCM and to conduct the FCM reconciliation within the PSCR case as a standalone component. First, Consumers argues that, if carrying costs are to be applied to the FCM over- or underrecoveries, the short-term debt rate should apply to both. However, the company states that, if the Commission declines to apply the short-term debt rate, the carrying cost should not exceed Consumers' WACC. Consumers' exceptions, p. 194. Second, Consumers asserts that the Staff and the company agreed to conduct a single-issue, 180-day proceeding to address the FCM reconciliation as demonstrated on the record:

> Staff witness Robert F. Nichols indicated that the Company's initially proposed 90-day schedule "is reasonable for Staff, but may also have drawbacks for other parties and the Commission." 8 TR 4680-4683. Staff therefore proposed an alternative 180-day schedule. In response, Company witness Myers explained that, although the Company continues to assert that the very limited scope of the FCM recovery proceedings could be reviewed and ordered in 90 days, the Company would also agree to Staff's proposed 180-day case schedule. 6 TR 2262.

Consumers' exceptions, p. 194. Consumers argues that the ALJ disregarded this agreement in her recommendation to include the FCM reconciliation in the PSCR proceeding. *Id*. In addition, Consumers states that inclusion of the FCM issue in the PSCR proceeding is unsupported by MCL 460.6j and that doing so ignores the importance of recording the FCM amounts in the same period that PPA costs are incurred to provide the true economics of the program in the company's financial statements. Consumers disagrees with the ALJ's finding that the company could wait to record the FCM revenue, arguing that it is not merely a matter of waiting to record the FCM revenue until it is approved. Therefore, Consumers requests that the Commission explicitly authorize a single-issue, 90-day or 180-day proceeding to address the FCM reconciliation. *Id*., p. 195.

The Staff takes exception, objecting to the ALJ's adoption of ABATE's proposal to allocate the FCM amounts on rate base. The Staff argues that the ALJ's recommendation ignores the Staff's evidence demonstrating that ABATE incorrectly asserted that the purpose of the FCM was to monetize imputed debt. According to the Staff, the June 7 order noted that the FCM is not related to imputed debt, but rather, its purpose is to reduce the company's risk and ensure impartiality in choosing between Consumers' owned and contracted resources. Staff's exceptions, p. 17.

The MEC Coalition also takes exception to the ALJ's recommendation. According to the MEC Coalition, the ALJ stated that, "the FCM is analogous to the return Consumers receives on company-owned assets and should be treated in the same way for cost allocation purposes." MEC Coalition's exceptions, p. 13 (quoting the PFD, p. 385). The MEC Coalition argues that such allocation treatment is inappropriate because the FCM is not created by rate base and is not calculated using imputed debt. Rather, the MEC Coalition contends that it is created because of the use of PPA generation. Therefore, the MEC Coalition avers that FCM costs should be allocated based on the allocation of the PPA costs on which the FCM is based. Accordingly, the MEC Coalition recommends that FCM revenue for capacity payments should be allocated directly to capacity cost allocators. The MEC Coalition asserts that FCM revenue for capacity payments should not be allocated 75% based on capacity and 25% based on energy (the 4CP 75-0-25 method) because the PPAs separate energy from capacity costs, making it illogical to reallocate FCM capacity costs partly to energy. MEC Coalition's exception's, p. 12. The MEC Coalition's allocation approach would "allocate the PPA *capacity* costs directly to *capacity* costs using

Allocator 121 (4 CP demand)," which is the most clear and logical approach that reflects the already separated capacity and energy costs, according to the MEC Coalition. *Id*., p. 14.

In its exceptions, ABATE argues that the ALJ erred by agreeing that FCM costs should be allocated according to rate base but declined to recommend that FCM costs be recovered through base rates due to the possibility that a rate case may not be filed annually. ABATE's exceptions, p. 14. ABATE contends that the ALJ's reasoning ignores Consumers' habitual annual rate case filings and disregards the lack of policy justification for treating FCM costs differently from any other base rate item. ABATE asserts that such an exception to traditional rate making should be reserved for costs that are going to impact the company's earnings, are demonstrably volatile, or outside of the company's control. Thus, ABATE requests that the Commission reject the ALJ's recommendation and authorize recovery of the FCM through base rates. *Id*., pp. 14-15.

RCG excepts, reiterating the arguments set forth in briefing and requesting that the Commission reject Consumers' proposed FCM methodology. RCG objects to Consumers' proposed FCM reconciliation process and argues that inclusion of the FCM in the PSCR is more appropriate. RCG also states that the company provided no justification to treat the FCM differently from any other PSCR cost. In addition, RCG dismisses Consumers' timing concerns between the recording of an FCM and recovery, explaining that, if included in the PSCR, the company would recover its FCM under its PSCR plan, through which costs are collected monthly. Lastly, RCG excepts to the ALJ's recommended carrying costs, asserting that Consumers' common equity return should be applied to any overrecovery as set forth in Act 304 of 1982 (Act 304). RCG's exceptions, pp. 26-28.

Consumers replies to ABATE, reiterating the arguments set forth in exceptions and arguing that the FCM surcharge should not be recovered in base rates. Consumers' replies to exceptions, pp. 61-63. Consumers explains that "accounting guidance requires the Company to collect revenues associated with an alternative revenue program, like the FCM, within 24 months of recording the revenue." *Id*., p. 63. According to the company, including the FCM in base rates risks that recovery will occur outside of the 24-month time-period and unnecessarily complicates the economics of the program because Consumers may not file a rate case annually. *Id*., pp. 63-64.

In response to RCG's argument that the company may not immediately collect an FCM, Consumers cites the settlement agreement approved in the June 7 order, which provides for an FCM on PPAs entered into after January 1, 2019, as evidence that an FCM for 2019 and 2020 PPAs is appropriate. *Id*., p. 65-66. Regarding RCG's suggestion for carrying costs, Consumers requests that the Commission reject RCG's recommendation because no legal authority establishes FCM revenues as a PSCR applicable cost and PSCR statutory costs are not appropriate for an FCM. *Id*., p. 66-67. Consumers contends that all other arguments set forth by RCG are unsupported by record evidence and should be rejected. *Id*., pp. 65-67.

Consumers also addresses the Staff's objection to the ALJ's recommendation to adopt ABATE's proposal to allocate FCM costs in proportion to the rate base allocated to each customer class. Relying on the testimony provided by the company and ABATE on this issue, Consumers supports the treatment of the FCM as a return on PPAs that can be assimilated to the return on rate base. Thus, according to Consumers, because the return on rate base is allocated using rate base in the COSS, the FCM surcharge should be assigned the production rate base allocator (390) instead of the production allocators for capacity and energy. *Id*., p. 82.

The Staff, in its replies to exceptions, dismisses Consumers' argument that, pursuant to MCL 460.6j, the FCM cannot be treated as a stand-alone component of the PSCR proceeding.

The Staff asserts that the company failed to demonstrate that such treatment is prohibited by MCL 460.6j. Staff's replies to exceptions, p. 39. The Staff adds its support for the ALJ's recommendation regarding carrying costs.

In its replies to exceptions, RCG reiterates that it disagrees with Consumers regarding the appropriate proceeding for the FCM reconciliation and disputes the company's timing concerns for recording the FCM. RCG also reiterates that the carrying costs should be applied to the FCM to represent the company's ROE for overrecoveries as stipulated in Act 304. RCG contends the ALJ did not support her recommendation for carrying costs. RCG's replies to exceptions, pp. 8-9.

ABATE responds to the Staff's and the MEC Coalition's objections to the ALJ's recommendation for allocation, arguing that the Staff and the MEC Coalition mistake the FCM's operation. ABATE repeats its arguments that the FCM serves as a return on PPAs and as an offset to the debt imputed to Consumers by crediting agencies for those PPAs. Thus, according to ABATE, the FCM should be allocated the same way as the cost of debt. ABATE's replies to exceptions, pp. 15-16.

In its replies to exceptions, the MEC Coalition reiterates its exceptions to the ALJ's recommendation regarding the FCM cost allocation and arguing that ABATE's allocation proposal based on analogizing the FCM to a return on company-owned assets is inappropriate. The MEC Coalition agrees with the Staff that the ALJ failed to consider the Staff's testimony on this issue and recommends that the Commission adopt Consumers' initial allocation proposal—allocation based on 4CP demand. MEC Coalition's replies to exceptions, pp. 134-135.

The Commission finds that the FCM amount requested by Consumers, as well as the PPAs eligible for the FCM, are not in dispute, and therefore the Commission adopts the PFD and finds that the FCM in the amount of $3,031,000 for 2019 through 2021, for the 55 PPAs requested should be approved. As to the recovery and reconciliation method proposed by Consumers, the Commission finds that the company's proposal for recovery as a surcharge and the Staff's proposal for inclusion as a standalone component in the PSCR are the most reasonable and efficient options. As the Staff explained, the FCM would be considered as an independent element of the PSCR proceeding, would not be considered a power supply cost pursuant to MCL 460.6j, and would have no impact on the PSCR calculation. 8 Tr 4677. Because the PPAs on which the FCM is based are approved in the PSCR proceeding, the Commission agrees that this option allows the PPA information to flow easily into the FCM. As to the company's timing concerns, the Commission is not persuaded by Consumers' argument, given that the Staff explained that the timing issue is remedied by the company waiting to record the revenue until it is approved. 8 Tr 4678-4679. Thus, the Commission adopts the PFD as to the reconciliation proceeding recommendation.

However, recognizing that the establishment of an FCM recovery methodology for Consumers is an issue of first impression, the Commission is amenable to the idea that adjustment to the process may be required in the future. The Commission does not anticipate that the timing of the FCM recovery will be an issue considering the solution set out by the Staff, but should Consumers find recovery timing to be problematic, it may propose and support an alternative proceeding in the future.

The Commission also agrees that carrying costs should be applicable to the FCM as it is relying on projected sales in its calculation with additional uncertainty involving the execution of new PPAs to be covered by the FCM. 8 Tr 4679. The Commission agrees with the ALJ's recommendation that the WACC should be applied to any overrecovery by Consumers and the short-term debt rate should apply to any underrecovery. As to the allocation of the FCM cost, the

Commission disagrees that ABATE's proposal to allocate the FCM costs according to allocation of base rates, which the ALJ recommended, is the most reasonable option. Instead, the Commission finds the 4CP 75-0-25 allocation method, originally proposed by the company and supported by the Staff, to be the most reasonable allocation method. The FCM surcharge will not be collected through base rates, and while it may be analogized to a rate of return, the Commission finds that allocation according to a power supply allocation method is more reasonable given that the FCM is tied to a PPA or power supply cost.

B. Deferred Revenue Recovery Mechanism

In the January 9 order approving a settlement agreement, the Commission resolved all issues in Consumers' last rate case, with the exception of one issue that was resolved by a settlement agreement approved on May 19, 2020. Pursuant to the settlement agreement approved in the January 9 order, Consumers was authorized to defer the revenue requirement for capital expenditures for the new business, demand failures, and asset relocation distribution programs. The Commission approved base amounts of $94,000,000 for new business, $87,000,000 for demand failures, and $24,000,000 for asset relocation. PFD, p. 319 (citing the January 9 order, Exhibit A, pp. 4-6, ¶ 8).

In the instant case, Consumers stated that its total 2019 revenue requirement was $6,300,000 for the deferred capital spending, as presented in its Exhibit A-85, which illustrates the calculation of the return on, return of, and property tax related to the capital spending above the amounts included in the settlement agreement. These amounts were also deferred in 2020, resulting in a total deferral of $12.6 million that the company seeks to recover in this proceeding. The company explained that, "[t]he 2020 deferral on line 13 [of Exhibit A-85] represents the amount that would have been in rates in 2020 if the capital spending above the amounts included in the settlement agreement would have been included in the settled rates established in Case No. U-20134[,]" noting that these amounts would have been included in rates had the terms of the settlement agreement permitted the company to file a rate case before January 1, 2020. PFD, p. 320 (quoting 6 Tr 2233). Consumers requested that: (1) a 12-month surcharge be established on January 1, 2021, to collect the $12.6 million deferral, and (2) the same deferral mechanism be approved in this rate case for the same three programs, based on capital spending above the amounts approved in the Commission's final order in this case.

As discussed in Section III.A.2.a.i. above, the Staff agreed to the continuation of the deferral mechanism subject to four stipulations, listed above, to which Consumers agreed.

The Attorney General objected to Consumers' request on two grounds: (1) the inclusion of the revenue requirement for 2019 and 2020 is contrary to the terms of the settlement agreement approved in the January 9 order; and (2) the continuation of the deferral mechanism will promote excess spending. ABATE also asserted that the company's deferral request includes no incentive to control costs. In response, Consumers stated that:

> The Company is not requesting recovery of the 2019 and 2020 revenue requirement associated with the deferred capital spending. The Company is seeking recovery of the amount that would have been in rates had the Case No. U-20134 Settlement Agreement considered the revenue requirement associated with the higher actual 2019 capital spending.

6 Tr 2255.

The ALJ found that the amount and recovery mechanism that the company proposes for deferred 2019 spending on new business, demand failures, and asset relocation programs is reasonable, and she recommended Commission approval subject to the Staff's stipulations. PFD, p. 323. The ALJ acknowledged that the company had not included 2020 spending in its request in this case. She agreed with Consumers that:

> Mr. Coppola's position is entirely unreasonable because it would result in the Company getting recovery of its investments in 2019, the removal of those investments from rate base in 2020, and then the reentry of those investments in rate base in 2021 when the Commission sets final rates at the conclusion of this case. That position should be rejected because it is inconsistent with basic principles of ratemaking.

PFD, p. 323 (quoting Consumers' initial brief, p. 371). The ALJ also dismissed concerns regarding excessive spending, explaining that spending for these programs are largely driven by customer requests or equipment failures that are outside the company's control, thus excessive spending does not pose a problem. PFD, pp. 323-324.

The Attorney General takes exception, arguing that the settlement agreement approved in the January 9 order, which governs the recovery, is clear that the deferred accounting mechanism applies only to the 2019 revenue requirement for excess capital spending incurred during the 2019 test year and does not apply to the revenue requirement for the 2020 test year. Attorney General's exceptions, pp. 39-41. She also opposes the continuation of the same deferred capital spending recovery mechanism (DCSR) for distribution new business, demand failures, and asset relocation, which the ALJ approved, subject to the Staff's stipulations. According to the Attorney General, the recovery mechanism, as described in the settlement agreement approved in the January 9 order, was intended to be a temporary one-year measure and should not be continued. Additionally, she argues that the company's proposal goes beyond a mere continuation of the same mechanism for the following reasons:

> First, as proposed, the mechanism does not limit the calculation of the deferred revenue requirement to only the difference between what [sic] the Company['s] proposed revenue requirement for 2021 and the level approved by the Commission and reflected in rates. As stated by Mr. Harry, the deferred revenue requirement is not limited to any spending level. Mr. Harry goes on to explain how the Company would calculate the deferred revenue requirement to be recovered in the next rate case. Second, the revenue requirement would be calculated as if the excess spending amount had been charged to rate base. The deferred revenue requirement would include the return on the investment at the Company's approved rate of

> return, plus depreciation and property taxes. In other words, the company wants to be made whole for any proposed capital spending disallowed by the Commission in this rate case for New Business, Demand Failures and Asset Relocations, plus potentially any additional amounts spent above the proposed level. Third, Mr. Harry also states that any balance in the regulatory asset associated with the DCSR mechanism would accrue interest at the Company's short-term borrowing rate.

*Id*., pp. 41-42.

The Attorney General goes on to state that authorizing Consumers to continue the recovery mechanism would "upend the normal regulatory model where the Commission reviews the evidence in a rate case" and determines what capital spending has been justified sufficiently to include in rate base. *Id*., p. 42. She warns that approval would allow Consumers to operate without any "real spending limits," which are not addressed properly by the Staff's stipulations, and would allow the company to recover amounts that presumably have not been found to be reasonable and prudent in this case. Lastly, the Attorney General disagrees with Consumers' argument that it has no control over capital spending in new business, demand failures, and asset relocation and argues: (1) new business projects have long lead times that should bring in new revenue that the company can retain until its next rate case and should offset some of the revenue requirement in between rate cases; (2) the deferred revenue recovery mechanism is unnecessary given the company's nearly annual rate case filings; (3) the company is not experiencing financial stress or under-earning from regulatory lag; and (4) the proper solution is that the company should better manage its capital spending so that recovery of excessive capital spending is not an issue. *Id*., pp. 43-44.

ABATE excepts to the PFD and argues that Consumers' proposed DCSR mechanism unreasonably shifts costs to customers and should be rejected by the Commission. ABATE contends that the company, not customers, should bear the risk of overspending and that permitting the DCSR mechanism provides little incentive for Consumers to control costs. ABATE's exceptions, pp. 15-17.

In reply, Consumers reiterates the arguments set forth in testimony and briefing. The company objects to the Attorney General's contention that the company is attempting to double the amount that should be collected by seeking recovery of the revenue requirement for 2019 and 2020. Consumers emphasizes that it is seeking recovery of the amount that would have been in rates had the settlement agreement approved in the January 9 order considered the revenue requirement associated with the higher actual 2019 capital spending. Consumers' replies to exceptions, p. 67. In other words, the company's request in the instant proceeding includes the 2019 revenue requirement related to the capital spending and the continuation of the 2019 revenue requirement through 2020. *Id*., p. 68.

In addition, Consumers maintains that approval of the DCSR mechanism would not upend the regulatory model or encourage excess spending as suggested by the Attorney General. *Id*., p. 69. The company asserts that deferral amounts would still be subject to review and scrutiny in a future rate case and that the programs included in the DCSR mechanism include costs that are driven by customers, not the company. Thus, Consumers states that approval to continue the mechanism is not "an open checkbook" or a grant of "unbridled authority to spend." *Id*. The company also notes that the Attorney General is incorrect that new revenue associated with the New Business program would coincide with capital spending timing because new revenues would not be collected until after the capital project is complete and in service. *Id*., p. 70.

In response to ABATE's concerns about a lack of spending restraint, Consumers reiterates that the program costs are driven by customers and describes ABATE's claims of excess spending as ill-founded. *Id*., pp. 70-71.

In reply to the Attorney General, the Staff explains that the new business, demand failures, and asset relocation distribution programs are unique because they are driven by customer demand, and thus, Consumers cannot spend without restraint. Staff's replies to exceptions, p. 46. The Staff continues that its stipulations add customer protections, prevent abuse by the company, and address the concerns expressed by the Attorney General and ABATE. *Id*., pp. 46-47.

The MEC Coalition generally supports the deferred spending mechanism but also includes the following additional recommendations to protect ratepayers and offset potential cost burdens that were not addressed by the ALJ: (1) two-way deferral (over/under spending); (2) prudency review before cost recovery; and (3) expanded reporting. MEC Coalition's replies to exceptions, pp. 115-117.

The Commission finds the ALJ's recommendation well reasoned and supported by substantial evidence on the record, and, for the reasons discussed in Section III.A.2.a.i. above, the Commission adopts the ALJ's recommendation subject to the Staff's proposed stipulations. Additionally, the settlement agreement approved in the January 9 order states that, "[t]he parties agree that the Commission should authorize Consumers Energy to utilize deferred accounting associated with actual spending above the threshold amounts indicated below during the 2019 test year in this case," with those amounts being $94 million for new business, $87 million in reactive demand failures, and $24 million in asset relocation. January 9 order, Exhibit A, pp. 4-5, ¶ 8. The parties further agreed that deferred accounting would be limited to the return on, return of, and property taxes associated with the actual capital spending above the threshold amounts. *Id*. The Commission finds that Consumers' request in the instant case complies with the settlement agreement approved in the January 9 order. As explained at length and in sufficient detail by the company, Consumers is not attempting to double its recovery in 2019, as suggested by the

Attorney General, but rather is seeking recovery of the amount that would have appeared in rates. 6 Tr 2233-2234. The Commission notes that, while the Attorney General is correct that the settlement agreement approved in the January 9 order allowed deferral treatment for the 2019 revenue requirement, the settlement agreement did not bind the Commission to a particular decision in future rate cases.

C. Conservation Voltage Reduction Incentive and Recovery Mechanism

In the June 7 order, the Commission approved spending for conservation voltage reduction (CVR) but did not address an incentive mechanism. Consumers described CVR as a technology that flattens voltage on the company's distribution circuits which reduces customer usage. The company explained that it is planning to incorporate CVR onto 500 circuits by 2032, resulting in a projected 80 MW capacity reduction and an annual energy consumption reduction of 185,000 MWh by 2025. Thus, in this case, Consumers proposed a shared savings mechanism (SSM) pursuant to MCL 460.6x and MCL 460.6a(13) as a CVR incentive, arguing that CVR is similar to DR in that it is a low-cost, demand-side solution that replaces more expensive supply-side resources. Consumers states that its CVR investment results in a wide, long-term earning gap compared to a traditional supply-side resource, specifically noting that the net present value (NPV) return from 2021 through 2040 is $8.1 million for CVR and is $41.2 million for a 50% owned/50% PPA solar resource. Consumers' proposed SSM allows the company to share 15% of the actual, realized benefit to its customers. The company explained that its proposed 15% SSM for the 2021 CVR incentive would be approximately $800,000 to be collected via a surcharge beginning in 2021. Consumers also requests authorization to reconcile the CVR surcharge in an annual 90-day proceeding.

The Staff, ABATE, and the Attorney General opposed Consumers' request for a CVR incentive via an SSM. The Staff noted that CVR was approved in the company's most recently approved IRP as the most reasonable and prudent means of meeting Consumers' energy and capacity needs, but it did not include an incentive. In the Staff's opinion, the company will not experience lost revenue because "CVR involves capital investments that allow the Company to earn a Commission approved rate of return on the spent portion of the capital approved in the Company's most recent IRP." Staff's initial brief, p. 152. Moreover, the Staff contended that:

> *if* CVR does result in decreased amounts of energy delivered to the end-use customer as the Company testified, then less energy will be sold and therefore sales will be reduced. This does not necessarily equate to lost revenue. Simply put, the Company forecasts its energy sales that are ultimately used to calculate electric rates. (Exhibit S-32, p 6.) If the Company has determined that its sales will be reduced by any significant amount due to CVR, the Company could adjust its sales appropriately and reflect the change in the sales projections used to calculate the Company's electric rates.

*Id*. (emphasis in original). In addition, the Staff asserted that CVR is part of the company's grid modernization and AMI programs and, therefore, an incentive beyond a return on the CVR investment is not appropriate. Finally, the Staff contended that the company's request is premature given that the Commission has requested comments on SSMs in Case No. U-20747 but has not yet issued an order in that case.

ABATE agreed with the Staff's argument that the company should not receive an incentive beyond the return on the CVR investment.

The Attorney General argued that the CVR technology corrects a problem in Consumers' distribution because customers previously received voltage in excess of their needs and were inappropriately billed for additional power costs. Thus, she averred that the company should not receive an incentive for correcting a problem and delivering quality power.

The MEC Coalition supported an incentive CVR but stated that Consumers' proposal is flawed and too generous because: (1) the incentive is not tied to performance; (2) the company uses avoided costs to calculate the incentive even though avoided costs are predominantly outside of the company's control; (3) the incentive is based on an absolute value of a more costly alternative supply-side resource; (4) the company's projection of on-peak energy savings resulting from CVR is too optimistic; and (5) Consumers' measurement of CVR energy savings is not transparent and should be done by an independent evaluator. In response, the Staff asserted that the MEC Coalition's calculation of the net benefit of CVR is incorrect because the calculation does not account for grid modernization and AMI programs with costs that have accrued since 2008.

The ALJ began her analysis with a recitation of MCL 460.6x(1) and MCL 460.6a(13) and explained that this issue turned on whether CVR is an "other waste reduction measure," as contended by the company and the MEC Coalition, or if CVR is part of grid modernization and a basic requirement for a regulated utility service. PFD, p. 329 (quoting MCL 460.6x(1)). The ALJ found that CVR is essentially a means to improve power quality to customers, albeit with the benefit of reducing energy use overall. The ALJ noted the Staff's point that CVR, among other advanced technologies, were used to justify the company's investments in AMI and grid modernization in 2008. The ALJ also stated that approval of a CVR incentive "raises the specter that Consumers will expect some incentive for almost any grid modernization technology" implemented that also reduces energy use. PFD, p. 330.

According to the ALJ, Consumers implied that, if its preferred mechanism is not approved and the company is forced to meet a minimum performance threshold before Consumers' shareholders start earning a return, it "could create an incentive to make minimal projections as to the potential savings in order to maximize an incentive opportunity." PFD, p. 330 (quoting 5 Tr 983). The ALJ agreed with the following assessment by the MEC Coalition:

> In essence, [Consumers] is saying that the Company feels free to skew the IRP inputs within the range of reasonableness in order to choose IRP inputs that are [a] resource on which the Company can earn a significant profit. Put another way, Consumers is asking the Commission to not hold Consumers accountable for the performance of its CVR program, or else Consumers will find another way to guarantee a profit for its shareholders.

PFD, p. 331 (quoting MEC Coalition's brief, pp. 153-154). The ALJ cautions that Consumers' admission should concern the Commission with respect to how incentives are evaluated and structured and as to the integrity of the IRP process. PFD, p. 331. With respect to the CVR cost allocation, the ALJ stated in a footnote that, because she recommended rejection of the CVR incentive, the allocation issue was moot. *Id*., p. 385, n. 1215.

Consumers takes exception to the ALJ's finding that the CVR program is not an EWR measure for which the Commission must authorize an SSM pursuant to MCL 460.6x(1). Consumers asserts that the CVR program is indeed an EWR measure that reduces annual electric demand, annual electric usage, transmission usage, and distribution usage, which results in lower costs and savings for customers. Consumers' exceptions, p. 196. Consumers reiterates that, although the program is cost effective and provides a benefit to customers, it results in lost earning opportunities for the company. Thus, the company argues that the CVR SSM is necessary to incentivize and encourage the company to utilize CVR, rather than supply-side resources, because supply-side resources would have higher potential returns on capital investment. *Id*., pp. 197-198.

Consumers also asserts that the ALJ's conclusion that CVR is a means to fundamentally improve power quality is inaccurate and reflects a departure from national views on CVR.

> CVR is not merely a natural result of a modernized grid. CVR is designed to reduce energy and capacity use throughout the year, particularly during peak load conditions, through voltage optimization. CVR reduces the amount of electric demand that is served on the electric system, which correspondingly results in

> reduced capacity costs by avoiding the need to maintain or obtain capacity resources. NARUC [National Association of Regulatory Utility Commissioners] has recognized that programs like CVR deliver energy and demand reduction benefits and encouraged state regulatory commissions to develop mechanisms to ensure that utilities and their customers are not financially burdened as a result of energy and demand reductions associated with voltage optimization deployment.

*Id*., p. 199 (internal citations omitted).

Turning to the ALJ's recommendation that consideration of any SSM should be deferred until the Commission issues a final order in Case No. U-20747, Consumers states that the Commission concluded the proceeding in Case No. U-20747 with an order on September 10, 2020 (September 10 order) that declined to adopt certain principles or specific procedures applicable to SSMs. However, Consumers acknowledges that the September 10 order stated that, to avoid double incentives, the Commission may not authorize an incentive for capitalized expenditures that receive a rate of return through traditional ratemaking. Consumers contends that its CVR incentive proposal does not constitute a double incentive because "[t]he NPV return opportunity from 2021 through 2040 of the proposed 15% shared savings mechanism plus the return on the CVR capital expenditures of $32.6 million is still significantly less than the 50% owned/50% PPA solar return of $41.2 million." *Id*., p. 201 (relying on 5 Tr 973 and Exhibit A-59).

Consumers also disagrees with the ALJ that it would "'skew the IRP inputs within the range of reasonableness in order to choose IRP inputs that are resources on which the Company can earn a significant profit.'" *Id*. (quoting the PFD, p. 331). Consumers argues that the company did not indicate, nor is there evidence in this case, that the company will skew IRP inputs. Lastly, Consumers contends that there is no reason to withhold an incentive until 50% of the shared savings are reached because the company only receives an incentive if there are realized customer savings.

The MEC Coalition takes exception to the ALJ's conclusion that CVR investments, in general, fail to qualify under Michigan law for an incentive. The MEC Coalition maintains that there is nothing in MCL 460.6x or MCL 460.6a(13) that states that a resource that provides power quality improvements, grid modernization, EWR, and other benefits cannot be considered an EWR resource. However, the MEC Coalition agrees with the ALJ that Consumers' proposed CVR incentive should not be approved because it is an incentive that is not tied to performance. MEC Coalition's exceptions, pp. 9-10.

The MEC Coalition also excepts to the ALJ's finding that its proposed allocation method for CVR is moot. The MEC Coalition argues that, "[w]hether or not the Commission approves or disapproves the Company's proposed CVR incentive, the Company will incur costs under its CVR program, and this is the first case to consider the appropriate allocation of those costs." *Id*., p. 11. Therefore, the MEC Coalition recommends that Consumers be required to provide additional analysis of CVR allocation in its next rate case and use the 12CP demand method in the meantime. *Id*.

In response to the MEC Coalition, Consumers agrees that Michigan law authorizes an incentive for CVR but disagrees that the company's proposed CVR mechanism is unreasonable. Consumers reiterates that its "proposed 15% shared savings amount reasonably makes CVR more comparable to a supply-side resource while still providing the large majority of the savings to customers." Consumers' replies to exceptions, p. 71. The company reiterates the arguments set forth in testimony and briefing, and asserts that its "proposed shared savings incentive is a 'reasonable and tailored' mechanism to encourage utilities to pursue innovative ways to find savings for customers that may not occur under the traditional utility regulatory approach." Consumers' replies to exceptions, pp. 71-74 (citing 5 Tr 975-976).

In its replies to exceptions, the Staff reiterates the arguments set forth in testimony and briefing. The Staff expresses concern that, if Consumers' incentive is approved, it will continue into perpetuity because the company will collect an incentive for as long as CVR is a technology that is used. The Staff also argues that the MEC Coalition's recommendation for a modified incentive should be rejected because updating equipment to today's technology does not warrant an incentive. *Id*., p. 41-43. In response to Consumers' claim that CVR results in lost revenues, the Staff reiterates that the company has not demonstrated that it has experienced financial harm by investing in CVR. The Staff restates that CVR technology is not an EWR measure, Consumers' proposed investment in a traditional technology over CVR is imprudent, and that CVR investments, in general, do not qualify for an SSM under MCL 460.6x. *Id*., pp. 40-42.

ABATE, in its replies to exceptions, asserts that an incentive for CVR technology is inappropriate under MCL 460.6x because CVR assets are already given equal consideration in the IRP process and capitalized. ABATE's replies to exceptions, pp. 11-13. ABATE agrees with the ALJ that CVR is a means of improving electric service to customers for which the company should not be rewarded. Further, ABATE argues that approving the incentive would inflate customer rates to keep the company from choosing capital intensive and more expensive resources instead of a cost-effective and capitalized option like CVR. *Id*., pp. 13-14.

In her replies to exceptions, the Attorney General requests that the Commission adopt the ALJ's recommendation. She asserts that, in its exceptions, Consumers merely reiterates the arguments set forth in testimony and briefing, which were rejected by the ALJ. The Attorney General adds that the company already used the CVR benefits to justify its AMI and grid modernization, and thus, adding costs now in an attempt to justify an incentive is inappropriate. Attorney General's replies to exceptions, p. 57.

In its replies to exceptions, the MEC Coalition requests that the Commission reject Consumers' flawed CVR incentive because linking the SSM to the net economic benefits of CVR fails to actually reward utility performance. However, the MEC Coalition agrees with Consumers that CVR, in general, should be treated as an EWR measure and that it is eligible for an incentive under Michigan law. The MEC Coalition explains "that CVR is a demand-side method of reducing energy waste, and therefore the Company may seek an incentive for it per the law's underlying policy 'to encourage the use of emergent technologies and innovation which may not be otherwise pursued under traditional ratemaking.'" MEC Coalition's replies to exceptions, pp. 95-96.

The Commission notes that MCL 460.6x(1) states, with emphasis added:

> Subject to section 6a(13), in order to ensure equivalent consideration of energy waste reduction resources within the integrated resource planning process, the commission shall by January 1, 2021 authorize a shared savings mechanism for an electric utility to the extent that the electric utility *has not otherwise capitalized* the costs of the energy waste reduction, conservation, demand reduction, and other waste reduction measures.

MCL 460.6a(13) reads, in pertinent part, with emphasis added:

> The commission shall consider the aggregate revenues attributable to revenue decoupling mechanisms, financial incentives, and shared savings mechanisms the commission has approved for an electric utility relative to energy waste reduction, conservation, demand-side programs, peak load reduction, and other waste reduction measures. The commission may approve an alternative methodology for a revenue decoupling mechanism authorized under subsection (12), a financial incentive authorized under section 75 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1075, or a shared savings mechanism authorized under section 6x if the commission determines that the resulting aggregate revenues from those mechanisms would not result in a reasonable and cost-effective method to ensure that investments in energy waste reduction, demand-side programs, peak load reduction, and other waste reduction measures *are not disfavored* when compared to utility supply-side investments.

In its September 10 order addressing SSMs, the Commission found that:

> under the plain language of [MCL 460.6x], it may not authorize an SSM for capitalized expenditures that are receiving a rate of return through traditional

> ratemaking. This interpretation is supported by the fact that no incentive is necessary to encourage such investments if the utility is already authorized to recover a rate of return on the investments. Allowing both capitalization and an SSM incentive could act as a double incentive which would be contrary to the goal of promoting reasonable and cost-effective investments.

September 10 order, p. 26. Considering the statute, the Commission's previous findings regarding SSMs, and the evidence in this case, the Commission finds that, while nothing in MCL 460.6x or MCL 460.6a(13) precludes a resource that increases energy efficiency, manages load, or otherwise reduces energy waste from being considered an EWR resource eligible for an incentive, approval of Consumers' proposed 15% SSM in this case would allow the company a double incentive on a capitalized asset. Consumers acknowledges this but seemingly tries to dismiss the statute's prohibition by stating that there is not a double incentive because of the "minimal" capital investments tied to the return even though the NPV return opportunity from 2021 through 2040 of the 15% proposed SSM plus the return on CVR capital expenditures amounts to $32.6 million. Consumers' exceptions, p. 201; 5 Tr 973; Exhibit A-59. The statute does not qualify the level of return such that assets earning only what a utility considers to be substantial returns are barred from the SSM eligibility. For the portion of an asset that is capitalized, as the CVR technology is in this case, the Commission does not find approval of an SSM appropriate.

Further, the Commission agrees with the Staff that CVR technology was found to be the most reasonable and prudent resource option in the IRP without the inclusion of an incentive. In this vein, if CVR was selected in the IRP process without the incentive, it becomes impossible to judge, after the fact, whether the inclusion of CVR with an incentive would have been selected in the IRP process, or whether another resource or resources would have been found to be more cost effective or otherwise preferable.

As to whether CVR technology qualifies for the SSM as an EWR, conservation, DR, or other waste reduction measure, the Commission declines to categorically exclude CVR technology from qualifying for an SSM. The Commission has previously found that similar technology could be included in an electric utility's EWR savings goal as a load management technology as permitted under the EWR statutes, MCL 460.1071 *et seq*.[31] However, in the instant matter, the Commission declines to approve the SSM because CVR technology is already capitalized. Additionally, the MEC Coalition's argument that approval of the incentive is inappropriate because it is not tied to any performance metrics is well-taken. Should the company wish to pursue an incentive in the future, it should include CVR with the incentive fully supported and with a proposal for performance accountability in its next IRP proceeding where the Commission can evaluate it in a holistic context alongside other resource options.

The Commission finds that, while CVR may be eligible for an incentive as an EWR technology when structured differently, the CVR SSM proposed by Consumers in this case should not be approved at this time. The Commission also agrees with the ALJ's conclusion that because the CVR incentive is not being approved, the company's allocation request is moot. PFD, p. 385, n. 1215.

[31] In Case No. U-20374, Indiana Michigan Power Company's (I&M's) most recent EWR reconciliation case, the Commission acknowledged that it had previously permitted I&M to include the savings achieved from its electric energy consumption and optimization (EECO) program, in its statutorily required EWR savings goals. The EECO program, similar to Consumers' CVR, achieves energy conservation through automated monitoring and control of voltage levels provided on distribution circuits. However, the Commission also departed from its previous orders including EECO in EWR savings because the program proved to not be cost effective. October 29, 2020 order in Case No. U-20374, pp. 14-16.

D. Long-Term Industrial Load Retention Rate/Hemlock Contract

Pursuant to 2018 PA 348, MCL 460.10gg (Act 348), which allows, with certain requirements, eligible large industrial customers to receive a rate for electric service based on the cost of a designated power supply resource, Consumers proposed a long-term industrial load retention rate (LTILRR) and contract with HSC and explained how HSC meets the requirements set forth in Act 348.

The MEC Coalition took issue with the O&M expenses associated with the LTILRR and HSC contract, asserting that because the expenses are projected, it is possible that "there will be a gap between the supposed and projected fixed operations and maintenance expense covered by the capacity charge and operations and maintenance expenses that are classified as variable and recovered through energy charges." 8 Tr 3596-3597. The MEC Coalition thus recommended that the Commission consider all O&M in excess of the amount covered by the capacity charge as variable O&M. In response, Consumers and HSC point to MCL 460.10gg(1)(e)(i) which requires the calculation of a capacity charge for fixed O&M expense at the time the contract is entered into.

The ALJ found that HSC is eligible under the statute to take service under a LTILRR and that the contract provides a net benefit to Consumers' customers. Therefore, the ALJ recommended that the Commission approve the LTILRR and HSC contract.

No exceptions were filed on this issue.

The Commission finds the PFD well reasoned and supported by substantial evidence on the record and, therefore, adopts the ALJ's recommendation to approve the LTILRR and HSC contract.

E. State Reliability Mechanism Calculation

Consumers, the Staff, and Energy Michigan calculated a state reliability mechanism (SRM) capacity charge pursuant to MCL 460.6w. Consumers provided a revised SRM capacity charge calculation that included variable PPA costs as fuel costs that increased the SRM capacity charge from $335.99 per MW-day to $447.71 per MW-day.

Energy Michigan opposed Consumers' calculation, arguing that it is inconsistent with the statute and the Commission-approved calculation method. Energy Michigan specifically took issue with two measures that increased the charge: (1) Consumers used a load forecast from its capacity demonstration case as the denominator on the United States Securities and Exchange Commission (SEC) Form 10-K rather than the MW value from the company's most recent annual report; and (2) Consumers converted the load forecast from MW to zonal resource credits (ZRCs). Energy Michigan explained:

> Since the numerator is the capacity cost of *all* Consumers Energy production resources net of offsets specified in MCL 460.6w, the logical denominator would likewise be the capacity MW value of *all* of the production resources. In fact, such a value was used in all of the SRM Charges that the Commission has approved for Consumers Energy as well as for DTE Electric.

8 Tr 4554 (emphasis in original) (footnote omitted).

Consumers responded that sourcing its load coincident with Midcontinent Independent System Operator, Inc. (MISO) from the company's PSCR forecast more accurately reflects Consumers' plans for the test year. Consumers continued that using ZRCs as the denominator in the SRM calculation is a more accurate measure of resource capacity in the MISO system and aligns with the method Consumers is required to use to demonstrate compliance with the MISO resource adequacy construct and the SRM capacity demonstration filing before the Commission.

Citing Energy Michigan's arguments, the ALJ found that Consumers' proposed revisions for calculating the SRM capacity charge should be rejected and that the SRM capacity charge should be set using the method previously approved by the Commission. PFD, pp. 334-335.

Consumers excepts to the ALJ's recommendation. The company asserts that the data provided in the SEC Form 10-K filing is historical and not accurate for the company's test year plans. Consumers requests that the Commission "approve sourcing the Company's load coincident with Midcontinent Independent System Operator, Inc. ("MISO") from the Company's PSCR forecast which more accurately presents the Company's plans for the test year." Consumers' exceptions, p. 203. The company further explains that its proposal is appropriate because "the denominator of the SRM Capacity Charge represents the amount of capacity that is the basis for the fixed costs in the numerator of the SRM Capacity Charge." *Id*., p. 204. Consumers notes that it revised its SRM calculation to include variable PPA costs to avoid non-SRM customers paying for variable costs to subsidize the SRM customers' revenue offset. According to Consumers, Energy Michigan's opposition is without basis because there is no reason a change in the calculation method cannot be proposed in this proceeding.

Consumers also objects to Energy Michigan's suggestion that the SRM charge denominator should be provided in MWs instead of ZRCs, arguing that the company established on the record that ZRCs are used by MISO for capacity and for compliance for MISO's resource adequacy and SRM demonstrations. Again, Consumers cites accuracy as a reason for using ZRCs as the denominator measurement in the SRM capacity charge. *Id*., pp. 204-206. Consumers insists that Energy Michigan's proposal would not result in an SRM charge that adequately addresses the cost of capacity for SRM customers and that Energy Michigan failed to adequately support its position. *Id*., pp. 206-207. Further, Consumers contends that Energy Michigan's proposal to include only the variable fuel associated with company-owned generation would produce the absurd result of the company receiving no credit for the fuel costs associated with PPAs that are relied on heavily by Consumers. *Id*., p. 207. According to Consumers, it demonstrated on the record that PPA variable costs equate to fuel costs that are similar to company-owned generation and thus are appropriately included in the SRM calculation. *Id*., pp. 207-208.

The Staff replies to Consumers, arguing that the ALJ properly considered all arguments made by the parties and correctly recommended adoption of the existing SRM calculation previously approved by the Commission. Staff's replies to exceptions, p. 52.

In its replies to exceptions, Energy Michigan reiterates the arguments set forth in testimony and briefing. Energy Michigan contends that the ALJ properly concluded that the source for the denominator for the SRM charge should be the MW value from Consumers' most recent annual report on SEC Form 10-K. Energy Michigan restates that Consumers' method was incorrect and unnecessarily complex and submits that the company has presented no new argument that justifies deviating from the Commission's previous orders directing the use of the MW value in the denominator of the SRM charge calculation. Energy Michigan's replies to exceptions, pp. 2-4. Energy Michigan also addresses Consumers' request to include variable PPA costs in the SRM charge, noting that the ALJ found Consumers presented its position in rebuttal—too late to be addressed fully—and did not present any new evidence as to why its position should be adopted. *Id*., pp. 4-5. Lastly, Energy Michigan dismisses Consumers' subsidy argument, explaining that it is impossible for SRM customers to subsidize non-SRM customers because "the <u>highest cost</u> that Consumers would reasonably and prudently incur to obtain additional capacity for AES customers resulting from an AES's failure to cover its capacity obligations under the SRM would be MISO CONE . . . ." *Id*., p. 6 (emphasis in original).

The Commission finds the ALJ's recommendation to be well reasoned and supported by the record. The Commission is not convinced that a deviation from the previously approved method to calculate the SRM is appropriate. After significant input from the Staff, stakeholders, and electric providers, including Consumers, the Commission approved the method for determining the capacity charge in Case No. U-18239. *See*, November 21, 2017 order in Case No. U-18239, pp. 66-67. The calculation approved used the SEC Form 10-K with the MW measurement in the denominator representing the company's total capacity supply. *Id*, p. 66. The Commission is persuaded by Energy Michigan's arguments that this method remains compliant with MCL 460.6w because the SEC Form 10-K represents the total MW values of resources as opposed to forecast load coincident with MISO, which is not contemplated by MCL 460.6w(3)(a). 8 Tr 4552-4558.

Further, the Commission declines to consider Consumers' proposal to include PPA variable costs in the SRM charge because the proposal was made on rebuttal and did not afford all parties adequate time to fully evaluate the proposal. The Commission therefore adopts the recommendation of the ALJ.

F. PowerMIFleet Program and Deferral Request

Consumers proposed a three-year, $12.2 million PowerMIFleet pilot program. The company explained that the pilot is intended to facilitate the benefits of EV adoption through managing grid impacts while the EV market is still small in an effort to avoid expensive, reactive adjustments once the market expands. According to Consumers, the pilot program includes rebate offerings under a "make ready" model rather than company ownership. 6 Tr 2305. The company explained that it would assess and adjust program components continually and provide an annual report to the Commission of its evaluations and changes.

Consumers provided the following cost estimate for the pilot program:

- Fleet Charging Infrastructure Capital (make-ready): a three-year cost of $4.5 million;

- Fleet Charging Infrastructure O&M (Level 2 rebates): up to $5,000 per port (cost of the rebate), for a three-year cost of $2.5 million;

- Fleet Charging Infrastructure O&M (DCFC rebates): up to $70,000 per public-use charger and $35,000 per non-public charger (cost of the rebate), for a three-year cost of $0.5 million;

- Education and Outreach: a three-year cost of $1.3 million for resources to recruit customers and site hosts for the Program, concierge service analyses, as well as educate all customers on the benefits of EVs and managed charging;

- Technical Development: a three-year cost of $3.4 million for the critical system underpinning charging data collection and analysis, demand response, and bi-directional power flow as well as allowance for two FTEs; and

- The fleet electrification concierge, workplace DR, and bi-directional power flow components will leverage rebates and make-ready investment from the fleet charging infrastructure component as well as Program support from the education and outreach and technical development components to operate, so there are not incremental costs for these components.

Consumers' initial brief, p. 411. Consumers added that, as the EV market evolves, the annual costs are expected to vary and that any difference between estimated and actual costs for each program element will be provided to the Commission.

Consumers also requested regulatory asset treatment of the PowerMIFleet pilot, which, if approved, would result in a deferred asset until the EV fleet program rebates and related O&M costs were verified. The company stated that this approval would allow Consumers to invest in EV charging infrastructure now and allow cost recovery later, accompanied by a prudency review before collection through rates.

ChargePoint, JCEO, EIBC/IEI, the MEC Coalition, ABATE, and the Staff made the following recommendations that were agreed to by Consumers: (1) reduce the minimum kilowatt (kW) requirement for dual port direct current (DC) fast chargers (DCFCs) to reduce the cost of DCFC rebates and minimize the demands of vehicle charging on the grid; (2) limit employee-owned vehicle charging to Level 2 chargers; (3) continue to pursue third-party funds from the Volkswagen settlement or other funding that may become available in the future; (4) ensure rebates are flexible within the overall pilot budget; (5) evaluate electrification of Consumers' fleet as part of the program; (6) identify and adapt open standards and protocols for fleet charging; and (7) address the managed charging objective of the PowerMIFleet pilot as part of its concierge service. PFD, p. 338.

The ALJ found that the recommendations made by the intervenors and the Staff and agreed to by Consumers are reasonable, improve the pilot, and should be approved. The ALJ also addressed intervenors' recommendations that the company opposed. First, the ALJ disagreed with ABATE and the Staff that a benefit/cost analysis is necessary at this time for a small pilot program. PFD, p. 338. Second, the ALJ disagreed with JCEO's recommendation to shift unused funds from PowerMIDrive to PowerMIFleet, to redesign incentive tiers, and to provide detailed reporting on a number of program attributes, reasoning that in the early stages of the pilot, flexibility in incentives and reporting requirements is beneficial. PFD, pp. 339-340. EIBC/IEI also recommended more extensive, mandated reporting on the pilot, as well as the inclusion of certain defined customer fleets (i.e., municipal buses, school buses), and proposed including electrification of the company's fleet in the next rate case. The ALJ found that reporting should remain flexible and she determined that mandating specific types of fleets to include in the program is unreasonable at this time. However, as to the recommendation to include company fleet electrification in the next rate case, the ALJ noted that a proposal to electrify the entire company fleet was not possible to develop in time, but recommended that Consumers consider a small pilot to extend the PowerMIFleet program to a portion of the company's fleet. PFD, pp. 341-342. Again, citing the need for flexibility in the early stages of the pilot program, the ALJ also rejected the recommendations from the MEC Coalition. PFD, pp. 342-343. The ALJ did not make a specific recommendation as to the deferral request for the PowerMIFleet pilot.

Consumers' exceptions are limited to the ALJ's recommendation that the company should consider a small pilot to expand the PowerMIFleet program to focus on a portion of Consumers' vehicle fleet. Consumers' exceptions, p. 208. The company does not oppose analyzing the company fleet as part of the concierge program. However, Consumers objects to being required to pursue even a small pilot in its next rate case because developing a pilot takes more time than what is available before the company's next rate case filing. Therefore, Consumers requests that the Commission not require the company to include the pilot in its next rate case filing. Consumers' exceptions, p. 208. Consumers also requests approval of its deferred accounting proposal for the PowerMIFleet pilot. *Id*., p. 252.

The Staff takes exception to the ALJ's conclusion that a site-specific benefit/cost analysis is unnecessary, arguing that the ALJ failed to address the Staff's reasoning for requiring such an analysis. The Staff recounts its testimony as follows:

> The Company claims that its proposed PowerMIFleet pilot will be a benefit to other customers by helping to lower the rates of other customers through increased grid utilization. As noted by Company witness Sarah R. Nielsen, however, proper site selection is necessary to ensure these benefits are realized. The best way to ensure the sites selected for inclusion in the pilot benefit other customers, it is necessary to conduct a site-specific cost-benefit analysis for potential credit recipients prior to their inclusion.

Staff's exceptions, p. 18 (internal citations omitted). The Staff insists that a system-level analysis is not sufficient and that an individualized benefit/cost analysis will require only moderate additional work by the company because Consumers must already prepare benefit/cost analyses for the large customers in the program. *Id*., pp. 18-19.

ABATE, in its exceptions, argued that the ALJ erred in finding that a benefit/cost analysis of the small pilot program was unnecessary at this time. ABATE states that the ALJ's finding is in direct conflict with the Commission's previous directive in the December 20, 2017 order in Case No. U-18368 (December 20 order), in which the Commission conveyed its expectation that a utility should provide a detailed benefit/cost analysis with any proposal for EV pilots. ABATE's exceptions, p. 19 (citing December 20 order, p. 35). ABATE insists that a benefit/cost analysis should be provided prior to the company incurring costs related to the pilot, and that without such an analysis, the Commission should reject the ALJ's recommended approval of the PowerMIFleet pilot. ABATE's exceptions, p. 20.

Consumers responds to the Staff, arguing that a site-level benefit/cost analysis is unnecessary for the PowerMIFleet program. The company disputes the Staff's representation of the company's witnesses and argues that she did not reference proper site selection to ensure certain benefits are realized. Consumers' replies to exceptions, p. 75. Consumers points to numerous excerpts from its rebuttal testimony, explaining that conducting such an involved, site-level benefit/cost analysis would increase the administrative burden and limit other program objectives. *Id*., pp. 75-76. Consumers requests that the Commission reject the Staff's proposed benefit/cost analysis.

In response to ABATE's exceptions, Consumers disagrees that the ALJ's recommendation conflicts with the Commission's previous directive in Case No. U-18368. First, Consumers argues that the benefit/cost analysis the company provided was sufficient. The company asserts that the level of detail requested by ABATE is not possible due to several unknown variables within the pilot and pilot's objectives. Second, Consumers points out that the MEC Coalition and ChargePoint agreed that Consumers' benefit/cost analysis satisfied the Commission's requirements in Case No. U-18368. *Id*., pp. 77-78.

In its replies to exceptions, ChargePoint contends that the Staff's proposed individualized benefit/cost analysis, which the ALJ agreed was not necessary, would risk increased administrative costs and program delays. In response to ABATE's argument that the December 20 order requires a more detailed benefit/cost analysis than that presented by Consumers, ChargePoint states that, "in fact, [the December 20 order does not] require any such analysis, nor would imposing such a requirement be good public policy." ChargePoint's replies to exceptions, p. 2.

EIBC/IEI disagrees with the Staff's and ABATE's arguments that a more detailed or site-specific benefit/cost analysis should be required for the PowerMIFleet pilot. EIBC/IEI argues that the pilot is in its infancy and that there is a need for flexibility at this stage. Therefore, EIBC/IEI requests that the Commission adopt the ALJ's recommendation to not require a more specific benefit/cost analysis at this time. EIBC/IEI's replies to exceptions, pp. 8-10.

ABATE, in its replies to exceptions, argues that the Commission should reject both the Staff's proposal for a site-specific benefit/cost analysis, and Consumers' PowerMIFleet proposal at this time, citing a failure to meet the Commission's requirements in the December 20 order. ABATE's replies to exceptions, p. 19.

In its replies to exceptions, the MEC Coalition contends that the benefit/cost analysis provided by Consumers is sufficient to satisfy the Commission's previous guidance in the December 20 order and that the Commission should reject the benefit/cost analysis proposed by the Staff and ABATE. The MEC Coalition requests that the Commission retain its flexible approach consistent with other state commissions. The MEC Coalition also argues that requiring the company to provide the benefit/cost analysis suggested by the Staff would result in delay and a waste of resources. MEC Coalition's replies to exceptions, pp. 98-103. Lastly, in response to Consumers' claim that it should not be required to provide a pilot for the fleet in its next rate case, the MEC

Coalition argues that there is ample time to prepare a small pilot program and that the company did not object to performing an electrification analysis for its own fleet. *Id*., pp. 104-105.

The Commission finds the ALJ's recommendation to be well reasoned and supported by the record. As it has with other pilot programs, the Commission finds that flexibility is warranted to allow the company to accomplish its information and experience gathering objectives. To support its request for approval of the PowerMIFleet pilot, Consumers explained the anticipated benefits as well as the costs of the pilot. 6 Tr 2288-2292; Consumers' initial brief, p. 411. Consumers also provided testimony and presented a benefit/cost analysis, explaining that the analysis was similar to the method used for the PowerMIDrive program. 6 Tr 2299-2303; Exhibit A-90. The Commission is satisfied that, for the purposes of a pilot program, the benefit/cost analysis provides adequate detail to justify approval and meets the Commission's previously stated guidance on its expectations for EV pilots. The Commission notes that it approved the settlement agreement, including the PowerMIDrive program, in Case No. U-20134 based on a similar benefit/cost analysis. *See*, January 9 order, p. 4; Attachment 3 to the settlement agreement in Case No. U-20134; Exhibit A-74 in Case No. U-20134.

At the outset of a pilot program, the Commission does not agree with the Staff and intervenors that a site-specific benefit/cost analysis is necessary because it would delay the implementation of the pilot and the associated benefits of the program. The Commission finds that approval of the pilot at this point will allow the company to gain experience in grid management and EV use in fleet vehicles. The Commission also adopts the ALJ's recommendation for the company to include a proposal for a pilot program for the company's fleet in the next rate case.

Lastly, the Commission also finds the company's request for deferral treatment to be reasonable, and noting that no exceptions have been filed with respect to the ALJ's recommended approval of deferred asset treatment, the Commission adopts the PFD.

G. Advanced Metering Infrastructure

RCG requested that the Commission eliminate or reduce the surcharges to AMI opt-out charges. RCG contended that Consumers has not provided any cost-based information to support the company's opt-out charges. In addition, RCG stated that the Commission's rules allow customers to self-read meters and report to the company and, therefore, meter reading costs for AMI opt-outs are unnecessary and punitive.

In response, Consumers argued that it did not propose any changes to the company's up-front and monthly charges related to its AMI opt-out program in this proceeding. The company also stated that the up-front and monthly charges established in its last rate case will continue without amendment, and that there is no evidence on the record to support RCG's position.

The ALJ agreed with Consumers that there is no basis to reject the AMI opt-out tariff and charges. The ALJ also noted that this issue has been repeatedly litigated and rejected by the Court of Appeals.

Next, Consumers requested that it no longer be required to submit an updated AMI business case in every rate case. The Staff recommended that the Commission continue the requirement because:

> The cost/benefit analysis also offers valuable insights into future programs where prudency relies on projected benefits that are anticipated to occur after upfront costs. It is important to continue to update the business case with *actual* benefits to be able to use the Company's experience with this project as a guide to judge future projects of a similar nature. If the Company expects to recover expenditures upfront for investments that deliver future benefits with no recourse for the Commission should these investments not deliver what they promise, the Company should at least be held accountable to reporting realized benefits for transparency,

> which is vital information for Staff, Intervenors, and the Commission to consider when making future decisions regarding utility investments.

8 Tr 4779. The Staff also took issue with the AMI business case presented in the instant case because certain upgrade costs were excluded, and the company discounted future revenue requirements to 2021 rather than to the beginning of the program in 2009. Adjusting for these issues, the Staff calculated an NPV of negative $2.2 million for electric service and negative $5.3 million in total.

Consumers agreed that the upgrade costs should be included and stated that the Staff misinterpreted the company's exhibit presenting the NPV calculation. Consumers contended that the Staff's NPV calculation is incorrect and departs from the method the company has used for the past decade.

The ALJ recommended that the Commission maintain the status quo as to the NPV calculation and require the company to file at least one more AMI business case in the next rate case. The ALJ also encouraged the Staff and the company to work towards an agreement on how to develop the AMI business case, including the appropriate base year, costs to include, and the discount rate to apply. PFD, p. 347.

Consumers excepts, asserting that additional updates to the AMI business case are unnecessary because the investment "is fully deployed and implemented, which seemed to be the threshold for finally terminating the AMI business case requirement in the Commission's Order in Case No. U-18322." Consumers' exceptions, p. 211 (citing the March 29 order). Consumers also argues that an updated business case is no longer necessary because the costs incurred going forward are subject to Commission review like any other investment for which the company does not produce new business cases to show that the original investment was justified. According to Consumers, "[a]t some point, the costs and benefits associated with subsequent maintenance and investments in a larger existing project must stand on their own, without regard to the cost-benefit analysis that justified the original project." *Id*., p. 210. Referring to the ALJ's finding that there is a dispute regarding the NPV calculation, Consumers argues that the dispute has nothing to do with the necessity of filing the business case. Finally, the company asserts that the Staff's conclusion that providing the business case is helpful in evaluating similar future investments does not justify the continued update. Consumers argues that continuing the update into perpetuity for a program that is fully deployed and implemented provides no useful information for evaluating other investments.

The Staff disagrees and states that, "simply because the business case was initially useful to the company to support the justification for the significant investment it made, does not mean that continued updates to the business case hold no value now that it has received its recovery." Staff's replies to exceptions, p. 31. The Staff adds that there are many benefits that are now materializing from the AMI installation that are useful in evaluating similar programs like the AAH and CRM programs. The Staff disputes Consumers' assertion that continuing the AMI business update requirement is unprecedented, and notes that the AMI program itself was an unprecedented investment, "representing $828 million in capital expenditures and a number of expected benefits that the Company is still investing additional ratepayer money in to attempt to achieve, such as demand response and theft detection, both of which the Company has requested additional recovery of in the instant case." *Id*., p. 32. Therefore, the Staff requests that the Commission continue to require the company to file an AMI business case.

RCG, in its replies to exceptions, shares the Staff's position that Consumers should continue to file an AMI business case, explaining that it would not be overly burdensome and that the information provided would be relevant to determining the reasonableness and prudence of current and prospective AMI investments. RCG's replies to exceptions, pp. 13-14.

The Commission finds, with respect to the AMI opt-out charges, the PFD to be well reasoned and supported by evidence on the record. Consumers has not proposed a change in the AMI opt-out tariff and RCG offers no evidence in support of its arguments; therefore, there is no evidence on the record with which the Commission could evaluate a change to the opt-out charges. Further, the ALJ is correct that RCG has made similar arguments previously, these arguments have been rejected by both the Commission and the Court of Appeals, and appeals to the Michigan Supreme Court have proven equally fruitless. *See*, *In re Application of Consumers Energy Co*, 503 Mich 1035; 927 NW2d 22 (2019) (lv den); *In re Consumers Energy Co,* 504 Mich 960; 932 NW2d 600 (2019) (recon den); *In re Consumers Energy Co*, 322 Mich App 480, 496; 913 NW2d 406 (2017); February 28 order, pp. 156-157. Therefore, the Commission rejects RCG's position and adopts the PFD regarding the AMI opt-out charges.

As to the AMI business case, the Commission agrees with the ALJ that the filing requirement should be continued. In Consumers' previous rate case, Case No. U-18322, the Commission responded to Consumers' similar arguments, stating that:

> merely completing the installation of meters and system enhancements does not conclude the implementation phase. . . . The ongoing benefits of the program have not been well-documented and, therefore, the Commission finds it necessary for Consumers to continue to update its AMI business case for the foreseeable future.

March 29 order, p. 80. In the instant case, the Commission finds the same rationale holds true. Although Consumers may have completed installation of the AMI technology, there are ongoing investments for technology and system upgrades, and the company has not yet achieved all of the projected benefits of the initial AMI investment and full implementation according to the company's own original definition of full implementation. *See*, 1 Tr 33-34 (remand) in Case

No. U-15645 (describing the benefits AMI would provide); Consumers' initial brief in Case No. U-15645, pp. 10-11. Therefore, further reporting is warranted and prudent to evaluate the realized cost and benefits versus the projected costs and benefits, and to provide transparency into how the program is delivering its benefits and whether any technology and programmatic adjustments should be made to realize the full benefits. Given the significant investment that Consumers has made—and continues to make—in AMI, the Commission finds that the information presented in the AMI business case is valuable to ensure accountability in realizing promised benefits. Additionally, the Commission is not directing the company to file the AMI business case into perpetuity as suggested in Consumers' exceptions but does find that continued reporting is necessary for the time being and is not overly burdensome.

As to the NPV dispute, while Consumers dismisses the significance of the dispute between the Staff and the company, the Commission finds the NPV to be an important component of the benefit/cost analysis and being able to draw conclusions about whether and how specific types of benefits are realized over time. In reviewing the company's updated business case in Exhibit A-89 and comparing it with the Staff's adjustments made in Exhibit S-18.0, the Commission observes that the differences between the calculations and what is included in those calculation of NPV, not surprisingly, results in differing NPVs, which paint different pictures of the overall benefit/cost analysis of the AMI program. The Commission finds that it is important that the Staff and the company come to some sort of common ground in arriving at an NPV that will allow the Commission to achieve its evaluation and transparency goals with the AMI business case filing. The Commission stresses that the purpose of the NPV should not be a regulatory "gotcha" with respect to the original investment, but to identify if there are new or missed opportunities to realize benefits from the existing and incremental investment in this technology. Therefore, the

Commission agrees with the ALJ's recommendation that the Staff and Consumers should work towards a consensus on the NPV calculation prior to the company's next rate case.

### H. Demand Response Surcharge

Consumers proposed to include a DR surcharge to manage over- and underrecoveries and the DR incentive, rather than including DR costs in base rates, which the company asserted will allow for more prompt customer refunds and timely collection of underrecoveries and financial incentives.

The Staff opposed inclusion of a DR surcharge and argued that, even if the Commission found the company's proposal to be reasonable, there are several issues with the proposal. First, according to the Staff, the surcharge method does not recognize any difference in revenue collected to cover the expense. The Staff explained that:

> If the surcharge is not set to collect all costs associated with DR, it would not be possible to reconcile the revenue collected to cover the costs, whether actual or included in rates. If the Company were to spend more on DR programs than was assumed in rates, but at the same time had higher sales, it is entirely possible that the Company could collect money for an under-recovery that did not actually occur. By separating all DR costs into a surcharge, both the revenues and costs could be reconciled, ensuring that both sides of the equation match. This would avoid compounding over/under-recoveries.

7 Tr 2918. Second, addressing the company's concerns about delays, the Staff contended that the company's first DR reconciliation was in 2017 and that future reconciliation proceedings would not be as lengthy. The Staff stated that, if the company waited to recognize a financial incentive until the Commission approved it, collecting the incentive within 24 months would be possible. ABATE echoed the Staff's opposition on similar grounds and claimed that the DR surcharge exemplified single-issue ratemaking.

In response, Consumers repeated its concerns about timing and disagreed that the company should wait for Commission approval of a financial incentive before recording it. Consumers argued that:

> recording the financial incentive in the same period of the associated costs aligns the cost of the DR program with the revenue, including the incentive. 3 TR 250. As the Company continues to expand DR under the Company's Clean Energy Plan, the performance incentive will be an important contributor to the Company's financial performance, and the ability to record the revenue in the period earned will provide a better economic picture of the program for both the Company and customers.

Consumers' initial brief, p. 423. However, Consumers agreed with the Staff that all costs and revenues should be included in the DR surcharge.

To begin, the ALJ explained that, pursuant to the September 15, 2017 order in Case No. U-18369, DR costs are addressed in a three-phase approach: (1) DR capital costs are approved in an IRP; (2) O&M costs are approved in a general rate case; and (3) a reconciliation of capital and O&M costs are addressed in reconciliation cases with any over- or underrecovery retained as a regulatory asset or liability until the next rate case, where it is included in rates along with any approved DR incentive. PFD, p. 347.

The ALJ agreed with the Staff that Consumers' DR surcharge proposal is flawed and recommended that it not be approved. The ALJ noted that the company's "primary concern appears to be related to timing, citing the extended time for processing the company's first reconciliation case, which was more complex due to issues concerning the design and implementation of the financial incentive, [as] well as the cost and revenue reconciliation." PFD, p. 350. The ALJ stated that, if the company continues to believe a DR surcharge is necessary, it should present a more complete proposal in its next rate case.

Consumers excepts to the ALJ's recommendation, arguing that approval of the DR surcharge would simplify the reconciliation process by eliminating the lag for recognition of over- and underrecoveries in base rates and allow the company to recover DR incentives within the required two-year period. Consumers insists that the DR surcharge is the most efficient and timely means of reconciling DR costs and managing the DR incentive. Consumers' exceptions, pp. 213-215.

In reply, the Staff contends that Consumers' exceptions contain the same arguments set forth in testimony and briefing and that the ALJ appropriately considered and rejected these arguments. The Staff requests that the Commission adopt the ALJ's recommendation. Staff's replies to exceptions, p. 56.

In its replies to exceptions, ABATE contends that Consumers' exceptions, which focus on a concern about delays in recovering DR costs in a rate case, ignore the company's own rate case filing practices and existing cost recovery methods. Further, ABATE rejects Consumers' attempt to add another single-issue ratemaking surcharge which would allow for a rate adjustment without the broader context of Consumers' total revenue circumstances. ABATE's replies to exceptions, pp. 17-18.

The Commission agrees with the ALJ that the DR surcharge should not be approved at this time. The Commission finds that the company's proposed DR surcharge mechanism is flawed, as described by the Staff, and leaves open the possibility that the company could collect funds for an underrecovery that did not actually occur. *See*, 7 Tr 2918. The company does not satisfactorily address this concern in rebuttal or exceptions, but rather repeats its arguments that the lag in recovery of under- or overrecoveries justifies the approval. The company also admits that its proposal is not ideal, in that removing all DR costs from base rates and addressing recovery through a surcharge would be the best approach. *See*, 3 Tr 252. While Consumers argues that timing issues justify the approval of a DR surcharge, the Commission does not find this to be a compelling reason given that the company could, as suggested by the Staff, wait to record the DR revenue until it is approved in the reconciliation. *See*, 7 Tr 2917-2918. Further, the company's use of the first DR reconciliation as an example of its timing concerns does not demonstrate a reoccurring issue with lag. As the ALJ suggested, should Consumers continue to believe the current process to be problematic, it can refile a proposal in its next rate case. Therefore, the Commission adopts the PFD and finds the company's request for approval of a DR surcharge to manage over- and underrecoveries and the DR incentive should be denied.

Because the Commission is not approving the DR surcharge, the Commission notes that the balance associated with the DR surcharge still exists, and therefore, the Commission directs Consumers to record the balance as a regulatory liability and include the DR surcharge amount in its next rate case.

I. Municipal Street Lighting

MAUI raised the following issues with Consumers' municipal streetlighting program and its conversion from high-intensity discharge lighting to LED lighting:[32]

- The Company's LED conversions have significantly higher costs than peer utilities, municipal utilities and third-party lighting providers;

- The Company's proposed LED fixture fee is too high and denies customers who have previously paid full cost for LED conversions fair recovery of their investments as originally projected in conversion proposals provided by the Company. The proposed fee also requires customers to begin paying for second-generation LED fixtures long before the customer-paid first-generation fixtures can be expected to require replacement;

[32] The LED conversion issue as well as the center-suspended streetlighting issue is also discussed above in Section III.A.2.d.i. and ii., respectively.

- The Company's LED conversions result in higher illumination than the replaced fixtures, driving up costs, wasting energy and potentially creating illumination hazards and nuisances;

- The Company's plan to convert center-suspension streetlights to pole-mounted LED installations is too expensive and needlessly increases illumination levels;

- The Company's burnout conversion program and proposed tariff structure create inequities among customers, who have little effective influence over the timing of costs that affect their rates;

- The Company's calculation and allocation of distribution plant-in-service rate base and O&M costs for the GUL and GU-LED unmetered rates contain methodological and data errors;

- The Company's streetlight reliability and outage restoration performance fail to meet company standards and customer expectations, and the company's plans for improving performance are unresponsive and insufficient;

- The Company's streetlight removal fee policy charges customers too much for removal of unwanted fixtures.

8 Tr 3982-3983.

Consumers responded that many of MAUI's proposed changes violate *Union Carbide Corp v Pub Serv Comm'n*, 431 Mich 135; 428 NW 2d 322 (1988), and that the Commission does not have the authority to direct the company to incur costs in a particular way. Consumers also argued that such large-scale proposals to redesign a statewide program are not suited for a rate case in which the company has not introduced the issue in its own filing and is thus limited by the time tables of the rate case proceeding.

The ALJ found that the issues raised by MAUI addressing cost of service or rate design have been addressed in the PFD, but that the remaining issues are not suitable for a rate case because of time constraints. That being said, the ALJ acknowledged that MAUI raised significant problems with the municipal lighting program that deserve careful evaluation given that the Commission has not focused on the municipal lighting issue outside of individual utility rate cases since the January 11, 2010 order in Case No. U-16186.[33] Thus, the ALJ recommended that the Commission direct the Staff to convene a technical collaborative to evaluate Consumers' municipal lighting program "given the substantial advances in energy efficient lighting in the decade since the order in Case No. U-16186." PFD, p. 353.

In exceptions, the Staff asserts that the ALJ failed to consider the Staff's arguments when outlining the company's position on the applicability of *Union Carbide*. The Staff claims that Consumers' argument that *Union Carbide* renders several of MAUI's recommendations unlawful is not entirely correct. The Staff states that, "[w]hile some of the specific recommendations of MIMAUI may appear to violate this standard, the Commission could achieve a similar result by disallowing costs in rates as unreasonable should the Company act in a manner inconsistent with the recommendations without intruding upon the management prerogative considered by Union Carbide." Staff's exceptions, p. 19.

In its exceptions, MAUI supports the ALJ's recommendation to convene a technical conference to evaluate and improve Consumers' streetlighting program but requests that the Commission provide specific parameters and a timeframe for such a conference. Specifically, MAUI asks that the conference include the following topics: (1) LED conversion costs and the pace of conversions, as well as ongoing maintenance and/or conversion of center suspension lights; (2) duration of bill credits for customers that have paid for LED conversions and ensuring that customers who paid for conversion out of pocket are not subject to cost recovery via the

[33] The ALJ prefaced this finding with a note that her review of Commission orders addressing municipal lighting was not exhaustive.

company's streetlight tariff; (3) streetlight reliability and outage restoration; and (4) net salvage value for streetlighting assets and corresponding tariff changes. MAUI's exceptions, pp. 1-5.

Consumers, in its replies to exceptions, does not dispute the Commission's authority to disallow unreasonable costs pursuant to *Union Carbide*. Rather, the company contends that MAUI's recommendations were not disallowance requests but, instead, requests for the Commission to direct Consumers to take certain action, which violates *Union Carbide*. Further, Consumers states that the Staff's request for a finding on the applicability of *Union Carbide* applies to a hypothetical request that is not ripe for determination and unnecessary to this proceeding. Consumers' replies to exceptions, pp. 10-12.

Consumers agrees with the ALJ that the instant case is not well-suited to address the magnitude of changes suggested by MAUI and that a technical conference would be an appropriate venue for addressing such issues. Although the company acknowledges that there is room for improvement in its streetlighting services, Consumers asserts that MAUI's request that the Commission provide prescriptive direction for the conference "is premised on numerous factual inaccuracies and on MAUI's failure to understand or appreciate all of the complexities of managing a statewide system of streetlights for numerous municipal customers with different needs, all balanced against the needs of Consumers Energy's other electric utility services." Consumers' replies to exceptions, p. 27. Therefore, the company requests "that any direction provided by the Commission for the content of the collaboratives should be framed in neutral and objective terms and should not presuppose that MAUI's criticisms of the Company's streetlighting program are, in all cases, legitimate." *Id*.

In its replies to exceptions, the Staff asks that, if the Commission approves a street lighting technical conference, the Commission should not adopt the recommendations by MAUI that presume a certain outcome prior to discussion. The Staff refers to MAUI's bill credits as an example. Staff's replies to exceptions, pp. 55-56.

MAUI agrees, in its replies to exceptions, with the Staff's recommendation regarding the applicability of *Union Carbide.* MAUI asserts that the ALJ failed to consider the similar argument MAUI made its reply brief that the Commission could use its authority over Consumers' cost recovery to achieve MAUI's streetlighting proposals. MAUI argues that its own examples of more cost-effective improvements for streetlighting demonstrate a reasonable basis for requiring reductions in Consumers' streetlighting costs. MAUI's replies to exceptions, p. 3.

The Commission finds the ALJ's recommendations regarding Consumers' municipal streetlighting program and conversion efforts to be well reasoned and supported by the record. The Commission agrees that these issues are significant and have a wide-ranging impact in Consumers' service territory, and that the significance of these issues would be difficult to address within the strict time constraints of a general rate case. Given that the parties did not except to the ALJ's recommendation for the Staff to convene a technical conference to address the municipal streetlighting program, the Commission adopts the ALJ's recommendation. The Staff shall convene a technical conference in 2021 to address Consumers' municipal streetlighting program including, but not limited to, LED conversion and updates to municipal streetlighting technology and service in the last decade.

As to the specific topics and parameters for discussion provided by MAUI, the Commission agrees that these topics merit consideration in the technical conference, but the Commission declines to impose with this order, a specific agenda of topics. The Commission finds that the details of the issues to be discussed and addressed are better left to the participants as part of the technical conference, with the Staff leading the effort to formulate the agenda. Leaving this matter to the participants allows for more thorough evaluation and input than the Commission can provide here based on the record in this case. In convening the technical conference, the Staff shall provide notice to the parties in this docket; establish a framework for participation; a conference schedule; and, in collaboration with participants, a list of topics, issues, and objectives to be addressed and achieved. At the conclusion of the technical conference, the Staff shall file with the Commission a report detailing its findings and recommendations regarding Consumers' municipal streetlighting program.

The Commission notes that its offices are currently closed and public meetings as well as workgroups are being conducted remotely due to the ongoing COVID-19 pandemic.[34] Because of the uncertainty as to how long the pandemic will impact Commission operations, the Commission places interested parties on notice that a technical conference may be conducted remotely and in compliance with any executive order or public health directives in effect at the time.

J. Low-Income Rates and Rate Affordability

1. Rate Affordability

Several parties raised issues regarding the affordability of Consumers' electric service. Relying on rate and billing data from the Energy Information Administration from 2018, the MEC Coalition demonstrated that, while Consumers' industrial rates are lower than average rates in 13 other states, its commercial and residential rates are higher than all but 10 states. The Attorney General made similar points regarding commercial and residential rate affordability and also stated that Consumers' rates have increased three percent per year over an 11-year period.

Consumers responded that, even with the rate increase requested in this case, the company's residential gas and electric bill combined represents approximately 3.5% of income, which is

[34] 2020 PA 228, MCL 15.263.

below the 6% unaffordability threshold cited by the Attorney General and the MEC Coalition. Consumers also noted that its rate increase will result in an average residential electric customer paying less than $4.00 per day in 2021 for electric service and that the impact will be even less because of Consumers' adjustments to its requested rate relief. 3 Tr 82.

The ALJ explained that the Attorney General and the MEC Coalition did not ask for specific Commission action with respect to rate affordability, but rather, asked that the Commission be cognizant of the escalation in commercial and residential rates over the past ten years. The ALJ noted her agreement with the intervenors. PFD, p. 355.

No parties took exception to the PFD on this issue.

The Commission appreciates the concern expressed by intervenors regarding rate affordability and is committed to its statutory obligations to ensure that rates reflect reasonably and prudently incurred costs of electric service. The Commission is also cognizant of the impacts of high energy bills on low-income customers, especially as the COVID-19 pandemic continues to impact Michigan residents. As part of its order detailing the Commission's COVID-19 response, the Commission, in response to concerns about energy affordability, directed the Staff to work with energy utilities and other stakeholders on potential improvements to affordable payment plans offered by the utilities. The Commission recognizes that concerns over energy affordability have also been raised in other recent rate case proceedings, and the heightened concerns over energy affordability resulting from the pandemic add urgency to improving options for customers needing assistance or flexibility in paying utility bills. *See*, July 23, 2020 order in Case No. U-20757 (July 23 order), pp. 46-47. Pursuant to that directive, the Staff issued a report on December 15, 2020 detailing its findings as a result of these discussions with energy providers and stakeholders. The Commission will continue to evaluate the findings and recommendations of the Staff to address energy affordability. The Commission also continues its efforts to convene the EWR low-income workgroup with the mission of coordinating and optimizing energy efficiency and clean energy offerings, improving energy affordability and quality of life for Michigan's low-income residents, and improving program design, accessibility, and delivery. Finally, as discussed below, the Commission continues to work with utilities and stakeholders to refine low-income rates to meet the needs of households facing energy affordability challenges.

2. Low-Income Rates

Consumers proposed a new low-income assistance credit (LIAC) of $30 per month targeted towards 4,200 of the company's most vulnerable customers and to increase the RIA provision, which is equal to the monthly residential customer charge, from $7.50 per month to $8.50 per month. 3 Tr 204-205.

The MEC Coalition and the Attorney General testified extensively regarding affordability issues for low-income customers, including arrearage impacts, income loss as a result of the COVID-19 pandemic, and assessments of the effectiveness in relationship to the objectives of the company's low-income assistance programs. The MEC Coalition and the Attorney General provided several recommendations:

> 1. Consumers Energy should transition low-income bill payment assistance to a fixed-payment Percentage of Income Plan ("PIPP"). This transition should occur over the 18-month period following this proceeding through a multi-stakeholder working group.
>
> 2. Consumers Energy should implement an arrearage management program ("AMP"). Implementation of an AMP should occur over the six-month period following the final order in this proceeding.
>
> 3. Consumers Energy should expand its low-income bill payment assistance to include the automatic enrollment of Food Stamp recipients into LIAC. Once the PIPP is implemented, automatic enrollment for these customers should continue as part of that program.

4. Pending implementation of a fixed-payment PIPP, Consumers Energy should:

a. Expand the LIAC program credit from $30 per month to $60 per month;

b. Provide a special LIAC benefit adder of $20 a month to customers who demonstrate that they participate in certain programs, including Temporary Aid to Needy Families (TANF) and Supplement Security Income (SSI), which indicate the customers fall in the extremes of low Poverty Level.

8 Tr 3686. The MEC Coalition and the Attorney General made additional recommendations for low-income assistance programs and cost recovery as well as recommendations as to how Consumers should address the ongoing impacts of the COVID-19 pandemic, which are detailed in testimony. *See*, 8 Tr 3686-3687.

Consumers disagreed with several recommendations set forth by the MEC Coalition and the Attorney General. First, the company asserted that the MEC Coalition and the Attorney General miscalculated the number of its customers earning at or below the federal poverty line. Second, Consumers asserted that the MEC Coalition and the Attorney General misconstrued the qualifications for some of the company's programs. Third, Consumers opposed the recommendation that customers receiving food stamp assistance should be automatically enrolled in the LIAC program, citing the need for the State of Michigan to share such information with the company and unknown implementation costs. And fourth, the company agreed that a PIPP program may be beneficial as a pilot but insisted that the 18-month time frame was not realistic and that requiring the transition was not appropriate.

The Staff disagreed with the MEC Coalition and the Attorney General, arguing that adding customers to the low-income programs or expanding the funds available does not solve the underlying problem, which is customers' ability to pay. The Staff continued that a rate case proceeding is not the appropriate venue to address a social problem like a customer's income or income inequality. The Staff added that it was also questionable whether increasing payments and decreasing uncollectible amounts would result in a benefit and noted that the proposal would be costly to other utility customers.

In response to Consumers, the MEC Coalition and the Attorney General stated that their data is reliable despite the small discrepancies pointed out by the company. The MEC Coalition and the Attorney General also argued that inclusion of customers between 150% and 200% of the federal poverty level (FPL) does not invalidate the conclusion that Consumers' programs are insufficient. In addition, the MEC Coalition and the Attorney General contended that the company's concerns about modifying its low-income programs are overstated. Finally, the MEC Coalition and the Attorney General asserted that enrolling customers who receive food stamps should not be an insurmountable task given the existing information exchanges between Consumers and the Department of Health and Human Services, and they argued that Consumers Affordable Resource for Energy (CARE) program is not duplicative of an AMP.

In response to the Staff, the MEC Coalition and the Attorney General asserted that the Staff failed to substantiate its claim that expanding the LIAC credit would be too costly. Otherwise, they contend, the Staff supports the proposed LIAC program.

The ALJ agreed in part with the MEC Coalition and the Attorney General and found that the assistance provided in the RIA program is "nearly meaningless" for many customers with a high energy burden and recommended that the Commission approve, until a more targeted program can be developed, a $30 per month credit for customers at or below 100% of the FPL, with an additional $20 for customers at or below 50% of the FPL. PFD, p. 361-362. The ALJ also recommended that the Commission direct the company to implement this change within 30 days from the date of this order. The ALJ noted that total program budget should not exceed $18,628,808, including administration costs.

The ALJ agreed with Consumers that developing a PIPP program within 18 months may be a challenge. She found that other methods, such as lifeline rates (providing a discounted rate for a certain number of kilowatt-hours (kWh) per month), may also be beneficial. The ALJ recommended that the Commission direct the Staff to convene a collaborative to address low-income rates with significant coordination with the existing Low-income EWR workgroup.

Consumers takes exception, contending that its proposed LIAC of $30 per month is effective and supports good payment habits and reduced consumption, and requests that its proposal be approved, along with the RIA credit. Consumers' exceptions, pp. 215-216. Consumers asserts that the ALJ's recommendation to expand the LIAC program would increase the revenue requirement to $12.6 million. The company explains that it does not object to the additional funding but disputes the ALJ's proposed changes to the LIAC program, namely the income enrollment qualifications. Consumers states that it is unable to verify income or percentage FPL, as suggested by the ALJ, and that it is currently working with the Staff to revise the RIA/LIAC tariff regarding income verification. *Id*., pp. 217-218.

Further, Consumers opposes the ALJ's recommendation to form a workgroup to address low-income rates, stating that such an effort is already underway in other dockets before the Commission. Consumers points to the July 23 order, which contains a directive to the Staff to work with energy utilities on improvements to affordable payments plans. The company also notes the settlement agreement approved in the September 10, 2020 order in Case No. U-20650, which included an agreement to develop a percentage-of-income pilot, and the EWR Low-income Workgroup as examples of efforts to address low-income rates. *Id*., pp. 218-219.

In exceptions, the Staff states that the ALJ did not provide a recommendation regarding the RIA and RSC credits, asserting that she recommended that the RIA stay in place for certain customers at what appears to be the current level. The Staff asserts that, historically, the RIA credit has been set equal to the monthly residential customer charge and, therefore the RIA credit should be set at $8.00 per month to match the Staff's proposed residential customer charge. Staff's exceptions, p. 9. As to the RSC credit, the Staff recommends that it be set at $4.00 per month to maintain consistency with historical practice of setting the RSC at 50% of the current customer charge. *Id*.

The Attorney General excepts, arguing that the ALJ erred when she failed to recommend that the Commission adopt the proposals set forth by the MEC Coalition and the Attorney General. The Attorney General takes issue with the ALJ finding that the $30 per month assistance credit through the RIA program is "nearly meaningless" but then found that maintaining the credit amount at $30 per month will allow more customers to obtain some relief. Attorney General's exceptions, p. 46 (quoting the PFD, p. 361). Also, contrary to the ALJ's assertion, the Attorney General contends that she accounted for the home heating credit (HHC) and other programs in her analysis and detailed why such assistance is insufficient. Attorney General's exceptions, p. 46. She cites low-income and poverty statistics among Consumers' customers and explains that her recommendations, which she claims were not considered by the ALJ, seek to accomplish the following:

- To enable and empower as many Consumers customers as possible to pay their bills,
- To make sure that Consumers customers can keep their utilities on,
- Reducing bad debt and reducing working capital expenses for the Company, and

- Reducing the time, effort, and money spent by the Company trying to track down delinquent accounts.

*Id*., p. 48. The Attorney General contends that Consumers' proposal does not address the underlying issue of unaffordable bills, and that the Attorney General's designed and targeted discount rate in the PIPP program, as well as her other recommendations, address this issue in a way that benefits customers and the company. Thus, the Attorney General requests that the Commission adopt her proposal in its entirety.

In its replies to exceptions, Consumers requests that the Commission reject the Attorney General's recommendations for low-income assistance. Consumers disputes the Attorney General's data and questions her conclusions based on her analysis. Consumers' replies to exceptions, pp. 111-112. Consumers also objects to the Attorney General's proposed 18-month timeline to transition the company's LIAC and RIA programs to a PIPP, stating that the timeline is unrealistic. *Id*., p. 112. As to the AMP suggested by the Attorney General, Consumers maintains that its Michigan Energy Assistance Program-funded CARE program operates very similarly and that the AMP would be duplicative. Consumers then reiterates that it is unable to verify customer income and argues that, absent additional funding, the LIAC credit should not be increased because it would reduce the number of customers assisted. *Id*., pp. 113-115. Lastly, Consumers asserts that the instant proceeding is not the appropriate docket for COVID-19 emergency relief measures because the matter is being addressed in Case No. U-20757. *Id*., p. 115.

In replies to exceptions, the Staff disagrees with the Attorney General's claim that the ALJ did not appreciate or consider her arguments. According to the Staff, the ALJ supported her decision with record evidence. Staff's replies to exceptions, p. 56.

The Attorney General, in her replies to exceptions, expresses support for the ALJ's recommendation to form a workgroup to address concerns with low-income rates. Attorney General's replies to exceptions, pp. 57-58.

In its replies to exceptions, the MEC Coalition avers that Consumers' concern regarding its ability to verify income for assistance eligibility is not a barrier given that the company is currently able to identify low-income customers for its existing offerings and uses methods similar to that proposed by the MEC Coalition. The MEC Coalition also argues that Consumers failed to provide a valid reason that it could not comply with the 30-day timeline for submitting a proposal to expand the LIAC program as recommended by the ALJ. As to the PIPP pilot, the MEC Coalition explains that Consumers is already in the planning process for developing a PIPP pilot for gas customers. Therefore, the MEC Coalition requests that the Commission direct the company to include electric customers in the PIPP pilot and include an arrears management plan in the pilot. MEC Coalition's replies to exceptions, pp. 105-115.

MCL 460.11 provides the Commission authority to establish eligible low-income customer or eligible senior citizen customer rates. Pursuant to this authority, Consumers seeks approval of its revised LIAC program to provide a credit of $30 per month and an RIA credit of $8.50 per month for eligible customers. The Commission appreciates the arguments set forth by the MEC Coalition regarding rate affordability and the difficulties faced by many Consumers' customers in affording their energy bills. However, the Commission declines to adopt the ALJ's recommendation to adopt part of the MEC Coalition's proposals to add an additional $20 LIAC credit for customers at or below 50% of the FPL and to eliminate the RIA program. As acknowledged by the MEC Coalition, there is currently no mechanism in place to identify the customers that would be eligible for the additional $20 credit. *See*, MEC Coalition's replies to exceptions, p. 112. Consumers states that its customers qualify for RIA and LIAC if they participate in the HHC and State Emergency Relief (SER) programs and thus, those programs validate customer income and need. *See*, Consumers' initial brief, p. 504. In other words, Consumers does not independently have the ability to verify the specified income levels suggested by the ALJ at this time. Income verification is a vital aspect of low-income program design and implementation and the Commission does not find it reasonable to approve $12.5 million in additional funds when the recipients of those funds are not yet identifiable. Therefore, the Commission declines to adopt the ALJ's recommendation to add an additional $20 credit available under LIAC to customers at or below 50% of the FPL.

Given the company's ongoing efforts to develop a PIPP program for its natural gas service pursuant to a settlement agreement approved in the September 10, 2020 order in Case No. U-20650, the Commission finds it reasonable to direct Consumers to develop a PIPP pilot for its electric service. The Commission agrees with the ALJ that a low-income collaborative would be beneficial to develop the pilot, as well as to address other issues surrounding energy affordability, including many of the points raised by the MEC Coalition and the Attorney General. The Commission notes that on December 15, 2020, the Staff issued a report pursuant to a Commission directive in Case No. U-20757, detailing its findings and recommendations regarding energy affordability concerns that have been heightened in light of the COVID-19 pandemic. The Commission observes that the Staff's report will serve as a good starting point for the low-income workgroup. Therefore, the Commission directs the Staff to convene a low-income collaborative, with the participation of Consumers, to address energy affordability. In this collaborative, Consumers shall provide a proposal for a PIPP pilot for its electric service.

As noted by the ALJ, the Commission's COVID-19 response, as well as emergency relief efforts, are being addressed in Case No. U-20757. PFD, p. 357, n. 1141. The Commission agrees that COVID-19-related relief and utility responses are better addressed in the existing Case No. U-20757 docket, and therefore, adopts the ALJ's recommendation.

Lastly, the Commission addresses the issue of the RIA credit and RSC credit amounts. The Commission adopts the ALJ's recommendation to retain the RIA credit. The Commission finds that the MEC Coalition did not adequately account for the benefit of the RIA credit in tandem with other assistance from the HHC and SER, and therefore, the Commission is not persuaded that eliminating the program is justified at this time. The company proposed an increase in the RIA credit to $8.50 per month and the Staff proposed an increase to $8.00 per month. The Staff supported its recommendation by explaining that the RIA credit and the RSC credit are tied to the residential electric customer charge. The ALJ addressed this issue on pages 380-382 of the PFD and recommended that the Staff's residential customer charge of $8.00 per month be adopted.

The Commission finds reasonable the Staff's argument that historically, the RIA credit has equaled the residential customer charge and that the RSC has been equal to 50% of the residential charge, and adopts the Staff's proposed $8.00 per month RIA credit and $4.00 per month RSC credit. For ease of reference to all issues pertaining to the company's low-income program, the Commission includes its RIA and RSC determination here, but the full overview and analysis of the residential customer charge is discussed in Section VIII.A.1.e.

## K. Independent Administrator Costs

The contested settlement agreement approved in the June 7 order required Consumers to utilize an independent administrator for competitive solicitations of supply-side resources. In the instant case, Consumers proposed to recover the costs associated with using the independent administrator through its PSCR clause, explaining that the IRP contested settlement agreement was silent on a cost recovery mechanism. Alternatively, if the Commission requires the company to include the costs in base rates, Consumers requests approval for $200,000 in additional O&M associated with the independent administrator.

No party opposed Consumers' proposal.

The ALJ recommended that the Commission approve the recovery of the costs associated with the use of an independent administrator through the PSCR. PFD, p. 363.

No exceptions filed on this issue and, therefore, the Commission finds the ALJ's recommendation reasonable and supported by the record and that it should be adopted.

## L. Accounting Approvals

Consumers requested accounting approvals for deferred regulatory asset or liability treatment for: (1) DCSR mechanism; (2) deferral and amortization of certain Karn 1 and 2 retention and separation (KRSP) costs; (3) PowerMIFleet deferred accounting; (4) CVR and DR incentives; (5) Storm Restoration;[35] and (6) the FCM.

Some intervenors took issue with the company's proposed accounting treatment as it pertained to deferred accounting for KRSP costs.[36] The Staff opposed the inclusion of $12,967,000 for 2020 in the company's deferral and amortization proposal on the grounds that those costs occurred outside of the test year. Consumers agreed to remove the 2020 costs from its proposal. 6 Tr 1880-1881. The Staff and Consumers agreed that it would be reasonable to record as a regulatory asset $7.413 million for 2021, $5.131 million for 2022, and $1.850 million for 2023, for a total of $14.394 million. 6 Tr 1880-1881; 8 Tr 4739; Exhibit A-168. However, the Staff recommended

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[35] Storm restoration expenses are addressed in Section V.C.2.c. of this order.

[36] The ALJ noted that other issues were raised by the parties with respect to accounting treatment of specific programs or incentives, but those issues are discussed in other parts of this order.

that the Commission "direct the Company to show, at the conclusion of the [retention and separation] plan, that the retention and separation expenses supported by the Company in this case went to the employees who signed the contracts. The Company's testimony demonstrates that there is a direct link between expense and employee benefit." 8 Tr 4739.

The MEC Coalition opposed the company's proposed 19-year amortization period and instead supported a 3-year amortization period for the KRSP costs. In the alternative, the MEC Coalition requested that the costs be securitized as part of the securitization of Karn Units 1 and 2. The MEC Coalition also argued that the amortization period should be consistent with the remaining life of the Karn units rather than the 19-year remaining life of the company's Campbell Unit 3. ABATE echoed the MEC Coalition's securitization request.

Consumers objected to the 3-year amortization period, arguing that the 19-year amortization is more appropriate because it represents the average remaining life of the coal plants and this time frame is typical for amortizing unrecovered costs associated with plant retirements. Further, Consumers stated that the 19-year amortization period minimizes impacts on customers by spreading the costs over a longer period of time. In response to the securitization arguments, Consumers pointed out that paragraph 3 of the contested settlement agreement approved in the June 7 order is clear that the financing order applies only to the unrecovered book value of Karn 1 and 2 and, therefore, the KRSP costs are not included in Karn 1 and 2 securitization.

To begin, the ALJ noted that, "the only issues that were raised with respect to the requested accounting approvals (other than those related to approval of specific programs or incentives that are discussed above) concerned the deferred accounting for Karn 1 and 2 retention and separation costs." PFD, p. 363. The ALJ was not persuaded that the amortization period should be tied to the average remaining life of a coal plant, as argued by the company. The ALJ agreed with the MEC Coalition that, "[p]lacing the costs into an asset imposes carrying cost for ratepayers by carrying an estimated $27 million operational expense for 19 years." PFD, p. 365 (quoting MEC Coalition's initial brief, p. 168). She noted that Consumers did not dispute this amount. As a result, the ALJ recommended that Consumers be required to adopt a three-year amortization period for the KRSP costs. Finally, the ALJ agreed with the company that the contested settlement agreement approved in the June 7 order did not mandate the inclusion of KRSP costs in the Karn 1 and 2 securitization.

Consumers excepts, reiterating that it supports the 19-year amortization period because it aligns with the average remaining life of the company's coal plants, which is typical for amortizing unrecovered costs associated with a plant's retirement, and it spreads recovery over a longer period of time. Consumers' exceptions, p. 221.

ABATE takes exception to the ALJ's recommendation and argues that the June 7 order included an agreement by Consumers to recover the unrecovered decommissioning costs for Karn 1 and 2 through low-cost debt financing rather than through traditional ratemaking, which provides a return. ABATE asserts that "[t]he recovery arrangement recommended by the PFD for the Karn 1 and 2 retention and separation costs in this proceeding would thus violate the terms of the Commission's July [sic] 7, 2019 Order in Case No. U-20165, as it does not provide customer savings and allows Consumers to earn a return on the costs at its authorized rate of return." ABATE's exceptions, pp. 18-19. Therefore, ABATE requests that the Commission reject the PFD and recommends that the KRSP costs be securitized along with the units' decommissioning costs.

In its replies to exceptions, Consumers disputes ABATE's claim that the company's deferral proposal is inconsistent with the settlement agreement approved in the June 7 order and that the Karn Unit 1 and 2 costs should be securitized. Consumers explains that "[t]he retention and separation costs at issue in this case are not in the unrecovered book value of Karn Units 1 and 2. Therefore, the Settlement Agreement does not prevent the Company's proposal in this case to defer and amortize these costs." Consumers' replies to exceptions, p. 79. Consumers states that ABATE's position relies on language that was inadvertently included in the June 7 order approving the settlement agreement but that the settlement agreement itself "is clear that the Company only agreed to seek a financing order (i.e., securitize) [for] the unrecovered book balance of Karn Units 1 and 2, and not the decommissioning costs" or retention and separation costs. Consumers' replies to exceptions, p. 80.

In its replies to exceptions, the MEC Coalition supports securitization or deferral of these costs but recommended an amortization period of 3 years as opposed to 19 years to reduce the cost to ratepayers. MEC Coalition's replies to exceptions, pp. 93-94.

ABATE claims that Consumers' deferred accounting proposal for Karn Units 1 and 2 is contrary to the language in the June 7 order. The Commission notes that the June 7 order reads as follows:

> The various compromises reached in this settlement agreement that the Commission views to be in the public interest include all of the following:
>
> * * *
>
> An agreement that provides potential customer savings by Consumers agreeing to seek recovery of the unrecovered book value and decommissioning costs of Karn 1 and 2 through low-cost debt financing in a separate proceeding, rather than continued recovery through traditional ratemaking which includes a return on these assets.

June 7 order, p. 78. In the settlement agreement approved by the June 7 order, the signatory parties agreed that:

> Karn Units 1 and 2 will be retired in 2023. The Company agrees to seek recovery of Karn Units 1 and 2 unrecovered book balance no later than May 31, 2023, filing an application under the applicable provisions of Customer Choice and Electric

> Reliability Act, MCL 460.10 et seq., seeking a financing order from the Commission authorizing Consumers Energy to recover the unrecovered book balance of Karn Units 1 and 2.

June 7 order, Exhibit A, pp. 3-4, ¶ 3. Given the discrepancy between the June 7 order and the settlement agreement, the Commission finds that the settlement agreement language prevails because this language was the result of careful deliberation by the signatories, and alteration by the Commission would render the agreement void. Therefore, the Commission agrees with the ALJ that Consumers' request for deferred accounting treatment for Karn Units 1 and 2 is reasonable, well-supported by the record, compliant with the settlement agreement approved in the June 7 order, and should be approved. The Commission approves deferred accounting treatment for up to $14.394 million for KRSP expenses. The company may include those costs in a future rate case for prudence review and rate recovery.

Regarding the amortization period, the Commission adopts the ALJ's recommendation to shorten the amortization period from 19 years to 3 years because the Commission is not persuaded that tying the amortization to the average remaining life of another coal plant in Consumers' fleet is a more reasonable option than tying it to the remaining life of the plant at issue, Karn.

M. Performance Based Ratemaking

The MEC Coalition raised the issue of implementing a PBR mechanism for Consumers, explaining that the need arises from the company's plans for significant investment in its distribution system and its relatively poor reliability coupled with high residential rates. The MEC Coalition asserted the importance of ensuring that Consumers' investments to improve reliability are cost effective and that the company is accountable for results. Relying on the Commission's report on the study of PBR, the MEC Coalition recommended that upward or downward adjustments to ROE or a performance incentive could be used to ensure performance accountability. The MEC Coalition acknowledged that PBR is being addressed in other Commission dockets and workgroups but stated that concrete proposals are not expected before the company's next five-year distribution plan case or rate case in 2021. The MEC Coalition therefore recommended that the Commission direct Consumers, with instructions similar to those provided to DTE Electric in Case No. U-20561, to include a distribution system PBR proposal in its next five-year distribution plan case to be filed no later than September 30, 2021, and in its next rate case to be filed in the spring of 2021.

Consumers objected to the MEC Coalition's arguments and recommendation, stating that there are numerous proceedings already addressing PBR and that they should be permitted to continue and to develop PBR mechanisms. Additionally, Consumers asserted that it does not have enough time before its next rate case and distribution plan case to develop a PBR proposal.

The ALJ disagreed with Consumers and found that, given the number of workgroups and collaboratives the company has been participating in, it is reasonable to expect that the company has "gleaned something" regarding PBR that could be presented in its five-year distribution plan case. PFD, p. 368 (emphasis in original). The ALJ noted that it is unlikely that a PBR mechanism would be implemented before 2023 and, therefore, she recommended that the Commission require Consumers, consistent with the instructions provided to DTE Electric in Case No. U-20561, to file a PBR proposal in its September 2021 distribution plan filing.

Consumers takes exception and requests that the Commission reject the ALJ's recommendation to require the company to provide a PBR proposal in its next distribution plan filing. Consumers expresses support for PBR and explains that it is involved in a collaborative with DTE Electric, the Staff, and other stakeholders addressing PBR and is participating in the MI Power Grid initiative, which includes plans for a financial incentives/disincentives workgroup.

Given these ongoing workgroups, Consumers asserts that it is premature to require the company to propose a PBR mechanism in a time frame much shorter than the 13 months offered to DTE Electric in Case No. U-20561, and unnecessary, considering that there is no immediate urgency in adopting a PBR mechanism. Further, Consumers notes there are existing mechanisms available to the Commission to incentivize appropriate spending. Consumers' exceptions, pp. 219-220.

The Attorney General excepts to the ALJ's recommendation regarding PBR as part of its exceptions addressing the SAIDI Glidepath. She contends that the ALJ's recommendation that the Commission take no action regarding PBR is unreasonable given the company's requests for increased expenditures without promised reductions or a commitment to achieve annual targets in SAIDI. Attorney General's exceptions, pp. 13-15.

In its replies to exceptions, the MEC Coalition expresses exasperation with the lack of reliability and inability to hold Consumers accountable for achieving reliability goals. Responding to Consumers' claim that it cannot provide a PBR mechanism in its next distribution plan filing, the MEC Coalition points to examples in other dockets where the Commission has fostered discussions of PBR mechanisms but has not yet issued a concrete PBR requirement for Consumers. The MEC Coalition avers that, given Consumers' requested increases in distribution spending, the Commission should reject the company's request to delay submitting a PBR mechanism in its next distribution system plan case. MEC Coalition's replies to exceptions, pp. 54-62.

The Commission finds the ALJ's recommendation to be well reasoned and supported by substantial evidence on the record. The Commission notes that Consumers generally supports PBR initiatives. *See*, 3 Tr 110. As evidence of that support, Consumers recounted its participation in collaboratives with DTE Electric, the Staff, and other stakeholders addressing PBR mechanisms and the MI Power Grid initiative that includes discussions of financial incentives and disincentives. *See*, 3 Tr 109-110; Consumers' exceptions, p. 219. The efforts to develop and apply appropriate PBR mechanisms date back to 2017, as acknowledged by Consumers, and multiple stakeholder sessions have taken place since then. 3 Tr 109-110. Consumers may prefer to wait until it is able to review DTE Electric's PBR proposal in its upcoming June 2021 distribution plan filing, but the Commission finds, as it did for DTE Electric in its last rate case, that Consumers has enough knowledge and experience with PBR mechanisms to include an initial proposal in its next distribution plan case to be filed no later than September 30, 2021. While the workgroups and collaboratives have been fruitful in terms of allowing participants to share information and ideas for PBR mechanisms, concrete movement forward on implementation has yet to materialize for individual utilities. As the ALJ pointed out, given the ongoing investigation of appropriate distribution system performance metrics, in which Consumers has been an active participant, the company should by now have some concrete ideas as to an appropriate PBR framework. PFD, p. 368.

Further, in response to the MEC Coalition's recommendation, the distribution plan, due to be filed no later than September 30, 2021, is better suited in terms of timing for PBR deliberation as opposed to including a proposal in Consumers' next rate case anticipated in the spring of 2021. Additionally, distribution plans allow for stakeholder input and set out the utility's five-year plans for its distribution system needs, maintenance and system upgrades, and system goals and reliability metrics, and benefit/cost analyses outside of the more formal contested case process. With the significant expenditures in Consumers' distribution system discussed elsewhere in this order, the Commission finds that it is important for the company to devise reasonable performance metrics with corresponding improvement targets, timelines for achievement, and available benchmarking data that can help lay the foundation for the subsequent formulation of a PBR mechanism tied to utility performance.

For the immediate next step in the distribution plan, the Commission is focused on having greater transparency around the specific performance objectives, metrics/measurements, investment strategies, timelines, and data sources. The Commission envisions the distribution plan setting out the company's plan that will then align with Consumers' distribution expenditure projections in the rate case that follows, as discussed above. Similarly, financial mechanisms to align with the PBR metrics developed in the distribution plan could then be applied to subsequent rate cases.

Similar to the directive provided to DTE Electric, the company should consider the following high-level guidance on the Commission's expectations for PBR:

> 1.The utility's financial PBR system should include both incentives and disincentives based on performance; incentive structures should be holistically considered in terms of impacts on potential earnings;
>
> 2. The utility should consider the pros and cons of a comprehensive PBR system, which would avoid concurrent regular annual rate cases and separate PBR reconciliations;
>
> 3. Performance metrics should include outcome measures (e.g., CAIDI) and not be limited to output metrics such as number of poles replaced;
>
> 4. Performance metrics should be linked to regional, national, and/or peer utility benchmarks, where possible;
>
> 5. Data and calculation methodologies should be well defined, transparent, and open for auditing/verification purposes;
>
> 6. Targets should be utility-specific; and
>
> 7. Potential areas of performance focus are safety, customer service (end-use customers, builders, interconnecting generators, etc.), timeliness and quality, reliability and resiliency, long-term costs, and innovation.

Consumers shall include a PBR proposal consistent with the direction in this order in its upcoming distribution plan to be filed no later than September 30, 2021, and shall share a draft with other stakeholders and the Staff by August 1, 2021.

## VII. REVENUE DEFICIENCY SUMMARY

In accordance with the foregoing findings, Consumers' jurisdictional revenue deficiency for the test year is computed as follows:

| | |
|---|---|
| Rate Base | $11,660,441,000 |
| Overall Rate of Return | 5.09% |
| Required Rate of Return | 5.67% |
| Income Required | $660,898,000 |
| Adjusted Net Operating Income | $593,523,000 |
| Income Deficiency (Excess) | $67,375,000 |
| Revenue Multiplier | 1.3391 |
| Total Revenue Deficiency | $90,220,000 |

## VIII. COST OF SERVICE, RATE DESIGN, AND TARIFF ISSUES

### A. Cost of Service

Consumers presented two versions of its COSS and explained the process as:

> A COSS by rate class is a systematic functionalization, classification, and allocation of a utility's fixed and variable costs to serve. Each COSS filed in this case serves two purposes. First, the process of preparing the COSS identifies and separates costs associated with the utility's production and distribution of electricity into the jurisdictional electric rate classes. Secondly, the COSS is used to determine the relative contribution to jurisdictional earnings from each of the Company's jurisdictional electric rate classes.

5 Tr 804-805. The ALJ noted that Version 1 of the company's COSS is consistent with the COSS previously approved by the Commission in the March 29 order and that "[t]he majority of disputes concerning COSS, pertain to COSS Version 2, and are discussed in detail below." PFD, pp. 369 (citing Exhibit A-16, Schedules F-1 and F-1.1). Below the Commission similarly addresses these issues.

1. Cost of Service Study Version 2

Consumers states that its COSS Version 2 starts with COSS Version 1 and includes the following: (1) an updated production cost allocator from 75-0-25 to 89-0-11; (2) a change in the distribution allocation for the general self-generation rate (Rate GSG-2); (3) modification of the treatment of capacity for interruptible load to be included in the COSS rather than rate design; (4) modification of the treatment of capacity for Rate EIP; (5) a modification in the breakdown of load profiles for General Service Primary Rates (Rate GP); and (6) a modification to the calculation of customer-related costs. *See*, 5 Tr 812; PFD, p. 369.

a. Production Cost Allocator

Consumers recommended the production costs be allocated according to 4CP 89-0-11, and stated that this update more appropriately reflects how the company's current generation plants operate based upon more recent data. 5 Tr 815. The Staff, however, recommended the continuation of the 4CP 75-0-25, as required under MCL 460.11(1), unless the Commission "determines that this method of cost allocation does not ensure that rates are equal to the cost of service." 8 Tr 4630 (quoting MCL 460.11(1)). The Attorney General recommended that the allocator be modified to 4CP 50-0-50. Kroger and ABATE recommended utilizing the average and excess (A&E) method and the MEC Coalition proposed a cost allocator of 70-0-30 based on CONE and the SRM capacity cost.

The ALJ rejected the various allocation proposals, concluding that Consumers, the Attorney General, ABATE, and Kroger did not demonstrate that the 4CP 75-0-25 method "does not ensure that rates are equal to the cost of service" as required under MCL 460.11(1). As such, the ALJ recommended "that the Commission continue the use of 4CP 75-0-25 for allocating production costs." PFD, p. 376. The ALJ noted that the Commission has previously held "that any party seeking to revise the production cost allocation method should also include an analysis based on the equivalent peaker method." *Id*. (citing January 31 order, pp. 100-101).

Consumers excepts, arguing that the ALJ failed to consider the changes that have occurred to the company's generating plant which "have presented the need to revise the production capacity allocator to accurately reflect cost of service." Consumers' exceptions, p. 222. Consumers asserts that it demonstrated that the 4CP 75-0-25 methodology should be updated to ensure that the company's rates appropriately equal the cost of service as required under MCL 460.11(1). Consumers' exceptions, p. 223 (citing 5 Tr 812-820; 5 Tr 836-844). The company reiterates its position, contending that its methodology utilizes the same analysis previously approved by the Commission but is updated with the most recent historical data, applying the appropriate allowance to calculate the minimum load produced by coal units, and excluding hydro plants from the calculation of base load. *See*, *id*., pp. 223-225. Consumers disagrees with the ALJ and argues that its analysis is not flawed because it "correctly reflects the new reality of the Company's generation plant, which is that '[t]he Company's investment in generation has evolved in the last few years; the Company has reduced its dependence on coal and increased its reliance on renewable energy resources and [DR] programs.'" *Id*., p. 226 (quoting 5 Tr 816). The company also asserts that the ALJ erred in finding that an analysis based upon the equivalent peaker method is required and contends that "the Commission should reject any suggestion that an analysis based on the equivalent peaker method should have been filed in this proceeding." Consumers' exceptions, p. 227.

In exceptions, the Attorney General asserts that the ALJ erred in adopting the 4CP 75-0-25 methodology. Specifically, the Attorney General states that her proposed 4CP 50-0-50 analysis "uses simple averages" and "removes the Company's inappropriate weighting of base load generation facilities." Attorney General's exceptions, p. 50. The Attorney General reiterates her position and her previously presented analyses, noting that her "second analysis can be appropriately viewed as a close facsimile to the equivalent peaker method the Commission has noted in the past." *Id*., p. 51. The Attorney General contends that her proposed methodology reasonably reflects the cost of service and that her method "results in a more equitable distribution of revenue requirements and rates among ratepayer classes." *Id*., pp. 52-54. She also asserts that Consumers' residential and commercial rates are higher when compared to regional peers while the company's industrial rates are competitive with the same group of peers. The Attorney General avers that this is mainly due to Consumers COSS methods "which disproportionately allocate a large share of its overall costs on a method that will favor higher load-factor customer classes at the expense of low load-factor classes." *Id*., pp. 53-54.

ABATE takes exception and reiterates its support for the company's proposal. ABATE argues that the "exclusion of certain coal and hydro generation costs was therefore not a flaw; it more accurately reflected the portion of those costs which should be considered base load given the evolution of Consumers' generation portfolio." ABATE's exceptions, p. 3. ABATE also contends that the Commission should reject the ALJ's finding that the equivalent peaker method should be submitted by any party seeking to revise the production cost allocation method because it overlooks numerous flaws with the average and peak method, which the equivalent peaker method is based upon. *See*, *id*., 4-6. Given the record, ABATE contends that A&E is the best methodology and should not be rejected in favor of the submission of an inferior method. Moreover, ABATE argues that, in Case No. U-18014, the Commission required the equivalent peaker method or an approximation for comparison purposes and that the Attorney General's proposal was sufficient for comparison purposes. ABATE's exceptions, p. 7.

In reply, Consumers reiterates its arguments, and further states that the Commission should reject the Attorney General's proposed 4CP 50-0-50 allocation "due to its incomplete assumptions and its failure to capture the impact on energy cost allocations." Consumers' replies to exceptions, pp. 84-86. The company also disagrees that its COSS and rate design disproportionately allocate costs to residential customers and disputes the Attorney General's "focus on percentage rate increases, as opposed to actual customer bill impacts, in [the] discussion of residential customer rate trends over the last five years." Consumers' replies to exceptions, p. 87-88.

In its replies to exceptions, the Staff agrees with the ALJ's determination that the parties failed to demonstrate that the 75-0-25 allocation "does not ensure that rates are equal to the cost of service" as required under MCL 460.11(1). The Staff objects to ABATE's contention that the company simply updated the Staff's methodology from Case No. U-17688; rather, the Staff states that Consumers actually "made several major modifications . . . that go beyond simply updating the generation data." Staff's replies to exceptions, p. 50 (citing Staff's initial brief, pp. 174-177). In reply to the Attorney General, the Staff contends that she did not demonstrate that the ALJ committed an error as "[a] rejection of a position does not constitute an error." Staff's replies to exceptions, p. 51.

In her replies to exceptions, the Attorney General contends that the ALJ properly rejected the company's 4CP 89-0-11 methodology because it "disproportionately allocates a large share of its overall costs on a method that will favor higher load-factor customer classes at the expense of low-load factor customer classes." Attorney General's replies to exceptions, p. 59. The Attorney General reiterates that her methodology, based upon the average and peak method, is the most appropriate methodology and that the 4CP 50-0-50 allocation reasonably reflects the relative cost of service.

The MEC Coalition replies, noting its support for the ALJ's recommendations and citing numerous Commission dockets to contend that the Commission has previously rejected similar arguments from Consumers and ABATE and that "the parties presented no basis for overturning those decisions here." MEC Coalition's replies to exceptions, p. 121. Further, the MEC Coalition states that the Commission should require Consumers to file "new production cost allocation studies in its next rate case based on the Equivalent Peaker and Probability of Dispatch methods from the NARUC manual." *Id.* The MEC Coalition also asserts that the ALJ did not err in stating that parties are required to include the equivalent peaker method if they seek to revise the production cost allocation. *See*, *id.*, pp. 127-129, 132-133. Furthermore, the MEC Coalition contends that the Commission should reject ABATE's claims regarding the A&E method and that ABATE inaccurately states that the 75-0-25 method "double counts peak demand by accounting for it in both the demand and energy components." *Id.*, pp. 130-131.

In response, ABATE argues that the average and peak method is not a reasonable methodology and that the Commission should utilize the A&E method. ABATE contends that the Attorney General largely restates her proposal and that her "proposed weighting and its analyses supporting the same are seriously flawed. Accordingly, the Commission should reject the Attorney General's recommendation." ABATE's replies to exceptions, p. 3.

MCL 460.11(1) states in pertinent part:

> The commission shall ensure that the cost of providing service to each customer class is based on the allocation of production-related costs based on using the 75-0-25 method of cost allocation and transmission costs based on using the 100% demand method of cost allocation. The commission may modify this method if it determines that this method of cost allocation does not ensure that rates are equal to the cost of service.

The Commission agrees with the ALJ that the parties proposing to modify the allocation have failed to demonstrate that the 75-0-25 method does not ensure rates are equal to the cost of service as required by the statute.

While Consumers contends that it utilized the Staff's methodology from Case No. U-17688, with updated data and modifications to better reflect how its current generating plants operate, the Commission finds that, as stated by the Staff:

> [b]oth in MPSC Case No. U-17688 and in following cases, the calculation found in Exhibits S-27.0 and S-27.1 were not the basis of Staff's position on the production cost allocation method. The calculation was simply a sanity check to assess the reasonableness of allocating 25% of production costs on energy and provided supplementary support to Staff's main arguments for supporting the 4CP 75-0-25 production cost allocator.

8 Tr 4636. The Commission also agrees with the ALJ's conclusion that Consumers' methodology is flawed, especially in the choice to exclude hydro plants and the removal of substantial coal plant costs from the baseload calculation.[37] The Commission is not persuaded by the company's arguments that these adjustments merely reflect its diversified portfolio and how the company's current generation plants operate based upon more recent data. Therefore, the Commission concludes that the ALJ properly rejected Consumers' 4CP 89-0-11 allocation proposal. Similarly, the Commission finds that the ALJ also properly rejected the Attorney General's proposed

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[37] In cross-examination, Consumers confirmed that, out of an unadjusted cost of over $3.9 billion, the minimum load adjustment removed approximately $1.9 billion from the costs allocated to baseload. *See*, 5 Tr 898-899; *see also*, Staff's initial brief, pp. 174-177.

4CP 50-0-50 allocation because it was unsupported and relies upon incomplete assumptions. *See*, 5 Tr 843; 8 Tr 4635-36.

The parties also dispute the ALJ's statement that "the Commission has determined that any party seeking to revise the production cost allocation method should also include an analysis based on the equivalent peaker method." PFD, p. 376 (citing January 31 order, pp. 100-101). The Commission finds that, in the January 31 order, the Commission adopted the administrative law judge's recommendation that "any party proposing to revise the production cost allocation method in a future case include in its evidentiary presentation an analysis using the equivalent peaker method or an approximation for comparison purposes" because it is "one method that may provide additional beneficial information about production cost allocation." January 31 order, pp. 100-101. As such, the Commission finds that the ALJ's conclusion is supported. Given the above, the Commission adopts the findings and recommendations of the ALJ, including the continued use of the 4CP 75-0-25 method for allocating production costs.

b. General Service Self-Generation Distribution Allocation

The company proposed to adjust the allocation of costs based upon the standby study analysis conducted by the Brattle Group (standby study). *See*, 5 Tr 820-821; Exhibit A-21. The Staff disagreed with the company's proposal and argued that the standby study was deficient, and that Consumers did not demonstrate that the standby study reflects the manner in which the company plans. EIBC/IEI also argued that Consumers' proposal was flawed and that the cost allocation for GSG-2 customers should be aligned with the costs for the LTILRR. *See*, 8 Tr 4506-4507.

The ALJ concluded that the Staff and EIBC/IEI "provided significant detail demonstrating that the company's Standby Study was deficient." PFD, p. 379. She further recommended that the Commission reject the company's proposed adjustment and require Consumers to provide a more complete standby study in a future rate case. *Id*.

Consumers takes exception to the ALJ's conclusion, arguing that she provided no analysis as to why the standby study was deficient other than citing the Staff's and EIBC/IEI's arguments. The company contends that the standby study considered all relevant data and information and no additional study should be required. Further, Consumers reiterates its contention that its LTILRR is different from customers with self-generation whose capacity needs are fully or partially met by its self-generation. *See*, Consumers' exceptions, p. 228. Consumers also states that the ALJ "provided absolutely no explanation or support as to why the study is so deficient that it should be refiled in a future rate case proceeding." *Id*., p. 229. The company argues that it has fully complied with the settlement agreement approved in the January 9 order and that it should not be required to submit an additional study merely because parties disagreed with the outcome of the study.

In reply, EIBC/IEI notes its agreement with the ALJ's recommendation and argues that, contrary to Consumers' exceptions, the ALJ considered the company's briefing, as exhibited by footnote 1199 on page 379 of the PFD, which references "the very same briefing cites that Consumers uses for its exceptions." EIBC/IEI replies to exceptions, p. 2. EIBC/IEI also contends that the ALJ properly relied on the evidence submitted by the parties "in making a determination as to the probative value to give the Brattle Group study." *Id*., p. 3. With regard to the ALJ's determination that an additional study should be required, EIBC/IEI states that the ALJ's recommendation is supported by her discussion of EIBC/IEI's testimony and briefing on the matter. *See*, *id*., p. 4 (citing PFD, pp. 387-379).

The Commission disagrees with the company's exceptions and finds that the ALJ set forth the parties' arguments regarding the deficiencies of the standby study before noting her agreement with the "significant detail" on the record demonstrating those deficiencies. *See*, PFD, pp. 376-379. The Commission further finds that the ALJ did not conclude that Consumers failed to comply with the settlement agreement approved in the January 9 order merely because she found the standby study to be deficient and recommended that the Commission require the company to provide a more complete standby study. The Commission adopts the findings of the ALJ regarding the deficiencies of the standby study, as fully described in the PFD. Further, as noted by the Staff:

> Currently standby customers are treated as members of the same class as other Primary customers for the purpose of distribution rate design. The Company has not shown that the coincidence of standby customers differs significantly from those other customers such that they should no longer be considered as taking distribution service in a similar enough manner to other customers in the class to merit their own class. The Company fails to note that the same study shows that, under the current method, the Company could be considered to be over-collecting distribution revenue from GSG-2 customers. In Staff's opinion, based on the foregoing, the evidence does not merit consideration of GSG-2 customers as a separate class for distribution purposes, so a potential "under-collection" is within the acceptable variation within the class.

7 Tr 2915-2916. Therefore, the Commission rejects the company's proposal to change the allocation of distribution costs for GSG-2 customers.

While the Commission declines to adopt the ALJ's recommendation for Consumers to file a more complete standby study as part of its next rate case, to the extent that Consumers wishes to revisit the allocation of costs to Rate GSG-2 in a future case, any such proposal shall include a more complete standby study that addresses the concerns of the Staff and EIBC/IEI.

c. Interruptible Load and Energy Intensive Primary Load Capacity Treatment

In the COSS Version 2, Consumers proposed to allocate capacity costs for interruptible load in the COSS rather than rate design. The ALJ found that the MEC Coalition disputed the recommended change in testimony but failed to address the issue in briefing. PFD, p. 380.

The Commission finds no exceptions were filed on this issue and that the company's proposal should be approved.

d. General Service Primary Rates Load Profile Adjustment

The company's proposal for two changes in the Rate GP Load Profile in the COSS Version 2 were undisputed on the record. *See*, 5 Tr 821. As such, the ALJ found that the company's proposal should be adopted. PFD, p. 380.

No party filed exceptions on this issue and the Commission concludes that the ALJ's findings and recommendation should be adopted.

e. Customer-Related Costs Adjustments

Consumers proposed adjustments to the customer-related costs in the COSS, which resulted in a recommended change in the residential customer charge to $8.50 per month, and $30.00 per month for General Service Secondary Time-Of-Use (GSTU) customers. The Staff opposed the company's adjustments, arguing that the Commission has previously ruled upon what should be included as customer costs, and calculated revised charges of $8.00 per month for residential customers and $20.00 per month for GSTU customers based upon the approved method for calculating customer charges. *See*, Staff's initial brief, pp. 169-172. The company generally agreed with the Staff's method in rebuttal. *See*, 5 Tr 855. The Attorney General recommended that the customer charges remain the same and the MEC Coalition requested that the residential customer charge be reduced, rather than increased, based upon the benefits provided by AMI meters.

The ALJ concluded that the Staff's proposed method of calculating customer charges was supported "and it has been approved by the Commissions in rate cases dating back decades, including two recent DTE cases." PFD, p. 382. The ALJ rejected the Attorney General's recommendation to maintain current customer charges, concluding that the increase is *de minimus* and would not affect energy conservation. In rejecting the MEC Coalition's proposal, the ALJ agreed with the company that the cost of the AMI "meter should be included in [the] customer charge, even if the meter itself provides some additional benefits beyond energy metering." *Id*.

The Attorney General takes exception, arguing that the increase is not *de minimus*. She also asserts that the company's rate design proposal is inconsistent with energy efficiency goals because it reduces the financial incentive for ratepayers to control their monthly utility bills through energy efficiency and conservation. Attorney General's exceptions, pp. 54-55. The Attorney General alleges that her Exhibit AG-2.17 shows that "the customer charge revenue associated with the residential classes is approximately 76 percent of their class cost responsibility" and that the "'fixed charge-equals-fixed cost' philosophy does not help in the development of efficient price signals." *Id*., p. 55.

In reply, Consumers notes that any objection to the increase in the Rate GSTU customer charge is without merit because it was not modified by the ALJ's recommendation. Consumers' replies to exceptions, p. 93. The company also states its agreement with the Staff's proposal to increase the residential customer charge from $7.50 to $8.00. Consumers again argues that a $0.50 per month increase to the customer charge is not inconsistent with energy efficiency principles as alleged by the Attorney General. "An increase of $0.50 to the residential customer charge is gradual and provides a balanced approach for moving towards a rate that sends a better price signal by reflecting cost causation and maintaining a stable rate design structure." *Id*., p. 94.

The Staff replies that the Attorney General's exceptions improperly indicate that her Exhibit AG-2.17 states that the customer charge revenue for the residential class makes up 76% of its overall class cost responsibility when it "clearly shows that residential customer charge revenue is 76.1% of total *customer-related* costs for the residential class." Staff's replies to exceptions, p. 52 (emphasis in original). The Staff avers that the Commission should note this misrepresentation in its review of the effects on energy efficiency.

The Commission finds that the recommendation to increase the residential customer charge from \$7.50 per month to \$8.00 per month, and maintain the Rate GSTU customer charge at \$20.00 per month, is well reasoned and supported in the record. The Staff's revision to the residential customer charge appropriately considers costs directly related to the customer as previously approved by the Commission. *See*, 8 Tr 4624-4625; *see also*, Staff's initial brief, pp. 169-171. The Commission is also not persuaded by the Attorney General's arguments relating to the customer charge being inconsistent with energy efficiency goals. The Commission agrees with the ALJ that the minimal increase advanced here is not likely to substantially reduce a ratepayers' control over their monthly utility bills through energy efficiency and conservation. Moreover, the customer charge should be accurate and reflect the costs and standards set forth by the Commission.

With respect to the MEC Coalition's proposal to reduce the customer charge based upon meter costs and AMI benefits, the Commission finds that the ALJ properly found that "the cost of the meter should be included in [the] customer charge, even if the meter itself provides some additional benefits beyond energy metering." PFD, p. 382. Therefore, the Commission adopts the findings and recommendations of the ALJ to increase the residential customer charge to \$8.00 per month and to maintain the Rate GSTU customer charge at \$20.00 per month.

The Staff also recommended that the company be directed to "separate certain customer-related costs that are attributable to specific rate classes or groups of rate classes and allocate them accordingly." 8 Tr 4626. Consumers disagreed with the Staff's recommendation and contends that it is unable to separate the costs. The Staff replies that the company failed to provide reasons for its inability and that separating costs is a common practice in accounting.

The ALJ found the Staff's proposal to be reasonable and "consistent with the Company's overall efforts to specifically assign individual costs to the class that caused those costs." PFD, p. 384. Therefore, the ALJ recommended that the Commission require Consumers to assign the Customer Care Center costs and Business Customer Care group costs to the appropriate customer classes in the company's next general rate case.

In exceptions, Consumers states that its "Business Customer Care group works not only with commercial and industrial customers but also serves a diverse population of small business, commercial, and industrial customers." Consumers' exceptions, p. 231. The company reiterates its contention that there is no mechanism currently available to allow it to separate these costs by customer classification as recommended by the Staff. Consumers, therefore, requests that the Commission decline to adopt the Staff's recommendation. In the alternative, Consumers "requests that the Commission grant the Company sufficient time to determine how to accurately revise the present allocations." *Id*.

The Staff contends that Consumers merely restates the arguments already rejected by the ALJ. In addition, the Staff states that, "[a]ssigning costs to customer classes that are solely or jointly responsible for those costs is not a foreign concept in cost of service ratemaking" and that Consumers "should be well equipped to create an allocator in future rate cases that assigns these costs appropriately to the customer classes responsible." Staff's replies to exceptions, p. 54.

The Commission agrees with the ALJ's recommendation that separating the costs is reasonable and consistent with the goal of specifically assigning costs to the class that caused the costs. *See*, PFD, p. 384. The Commission is not persuaded by the company's claim that it is unable to separate the costs by class as proposed by the Staff. *See*, 3 Tr 247; 5 Tr 855. Therefore, the Commission adopts the findings and recommendations of the ALJ, and Consumers should assign the Customer Care Center costs and Business Customer Care group costs to the appropriate classes in its next general rate case.

f. Other Cost of Service Study Proposals

i. Substation Ownership Credit Calculation

The company set forth its substation ownership credit calculation in Exhibit A-19. As noted by the ALJ, "no party disputed the method or resulting calculation of the credit." PFD, p. 384.

No exceptions were filed on this issue. The Commission finds that the company's substation ownership credit calculation should be approved.

ii. Mid-Peak Summer Fuel for Generation and Mid-Peak Purchased Power Accounts

The MEC Coalition noted that, in Consumers' "allocation of fuel and purchased power expenses, Mid-Peak Summer Fuel for Generation and Mid-Peak Summer Purchased Power are allocated to Allocator 103 – Energy On-Peak @ Gen Summer" whereas they "should be allocated based on Allocator 108 – Energy Summer Mid-Peak @ Gen." 8 Tr 3633. As noted by the ALJ, the Staff agreed that these expenses should be allocated based on Allocator 108. Staff's initial brief, p. 180; PFD, p. 385.

In exceptions, the Staff avers that the ALJ properly acknowledged the allocation error, but failed to provide a recommendation to address the error. As such, the Staff recommends that "the Commission correct for the error referenced by the ALJ and allocate Mid-Peak Summer Fuel for Generation and Mid-Peak Summer Purchased Power on Allocator 108." Staff's exceptions, p. 29.

The Commission agrees with the MEC Coalition and the Staff and concludes that Mid-Peak Summer Fuel for Generation and Mid-Peak Summer Purchased Power should be allocated based on Allocator 108.

iii. Allocation of Surcharges

Consumers provided Exhibit A-20 showing the allocation of surcharges for the FCM, the DR refund, and deferrals from Case No. U-20134. The Commission notes that the issues pertaining to the FCM, including the appropriate cost allocation, are addressed above in Section VI.A. and will not be restated here.

Additionally, in footnote 1215 of the PFD, the ALJ stated that, because the CVR incentive was rejected, the recommendations regarding cost allocation of the incentive are moot. PFD, p. 385.

In exceptions, the MEC Coalition disagrees with the ALJ's finding of mootness, and argues that the company will incur CVR costs whether or not the Commission approves its CVR incentive. Therefore, the MEC Coalition recommends that Consumers be required to provide additional analysis of the CVR cost allocation in its next rate case and that the company should use the 12CP allocation for CVR program costs in the interim. MEC Coalition's exceptions, p. 11.

Consumers replies, requesting that the Commission reject the MEC Coalition's request for additional analysis to be presented in the next rate case proceeding. The company contends that the MEC Coalition "provides no support as to why the Company should be required to perform the additional analysis beyond their disagreement with the proposed CVR allocation" and that, as previously stated, its "proposal to allocate the CVR Program Incentive, using allocator 230 – Class Peak at Primary is reasonable." Consumers' replies to exceptions, p. 90, 91 (citing 5 Tr 829).

As indicated above, the Commission rejected the company's CVR incentive. The Commission agrees with the ALJ's finding that the recommendations regarding the cost allocation are, therefore, moot.

iv. Streetlighting

MAUI raised concerns regarding Consumers' unmetered lighting rates, Rate GUL and Rate GU-XL. As noted by the ALJ, "[t]he company appears to have made several adjustments to its COSS to address certain concerns raised by Mr. Bunch and MAUI." PFD, p. 387.

No exceptions were filed on this issue and the Commission concludes that the ALJ's findings and recommendations are adopted.

v. Load Profiles

In exceptions, the Staff contends that the ALJ did not address Consumers' use of sampling in its load profiles. The Staff reiterates its disagreement with the use of sampling and again suggests that the company be required to use load data from its AMI meters in the next rate case. The Staff avers that "[s]ampling is unnecessary when the Company's AMI system can provide nearly all of the actual load data, a benefit for which the Company's ratepayers are paying." Staff's exceptions, p. 28.

Consumers replies, reiterating its disagreement with the Staff's proposal. *See*, Consumers' replies to exceptions, p. 83 (citing 5 Tr 859). The company contends that adopting the Staff's recommendation:

> would bring additional expenses to the Company. In order to manage the large amounts of actual data that would be required under [the Staff's] recommendation, the Company would incur an estimated cost of $100,000 to $150,000 for external consultant rework and set up for processing such large amounts of data. In addition, the Company would incur a $20,000-$35,000 annual expense for continued maintenance.

Consumers' replies to exceptions, p. 84. Therefore, the company restates that the Staff's recommendation should be rejected because the Staff "has failed to show that the Company's process is inaccurate and inappropriate, that it conflicts with industry accepted principles, and that such a recommendation would warrant such additional costs." *Id.*

The MEC Coalition replies that it supports the Staff's exception regarding load data. The MEC Coalition contends that "[a]ctual AMI data provides more accurate load data and more accurate load profiles" and Consumers should be required "to use actual load data to build its load profiles in the next rate case." MEC Coalition's replies to exceptions, pp. 135-136.

As noted in Section III.A.2.h. above, the Commission recognizes that additional effort may be needed to fully utilize AMI data for load forecasting. Therefore, the Commission declines to require the use of actual AMI data in the company's next general rate case, but expects updates on this effort to be included in the distribution plan to be filed in 2021.

g. Case No. U-20134 Settlement Agreement

In accordance with the settlement agreement approved in the January 9 order, Consumers conducted the standby study, as discussed above. The MEC Coalition alleged that the company did not comply with the terms of the settlement agreement, arguing that the company's study "did not attempt to allocate distribution costs via any method other than class peaks" and requested that the company be required to develop an alternative allocator in its next rate case. MEC Coalition's initial brief, p. 213. ABATE also took issue with the application of the class peak allocator, arguing that it should not be applied to each of the separate rate classes and subclasses. Consumers generally agreed with ABATE but stated that peaks should be calculated at the voltage level to better represent how its system is designed. *See*, 5 Tr 848.

The ALJ concluded that Consumers complied with the terms of the settlement agreement approved in the January 9 order. In addition, the ALJ stated she "agrees with ABATE and finds that although the MEC group's recommended approach may, in theory, offer some additional precision in the assignment of distribution costs, without additional information about how such an analysis would be done, it appears to be infeasible at this point." PFD, p. 392.

In exceptions, the MEC Coalition notes that it "does not take issue with the ALJ's conclusion that Consumers filed a study as required by the settlement agreement in U-20134" and that issues not resolved by the study "may be addressed in a future proceeding." MEC Coalition's exceptions, pp. 7-8. However, the MEC Coalition disagrees with the ALJ's finding "that the necessary analysis is 'infeasible' based on available resource and technology" but nevertheless states that it does not except to this part of the ALJ's conclusion as it may also be resolved in a future proceeding. *Id*., p. 8.

The MEC Coalition also takes exception to the ALJ's statement that she "agrees with ABATE" as it is ambiguous and could mean that she "agreed with ABATE's criticism of the need for a more detailed study in a future proceeding" or that "she supports ABATE's alternative distribution cost allocation approach proposed in this case – *i.e*., aggregating rate classes . . . ." MEC Coalition's exceptions, p. 8. Therefore, the MEC Coalition states that "the Commission should require the Company to examine the contribution of each class and rate schedule to peak loads on the shared components of the distribution system." *Id*., p. 9.

In exceptions, ABATE argues that its proposal to apply the class peak method to aggregated demand by rate class should be adopted rather than maintaining "the status quo which ABATE, the Company, and Staff agree is flawed . . . ." ABATE's exceptions, pp. 8-9. ABATE restates its position that its approach is more closely related to cost causation and is compatible with Consumers' existing tariffs. *Id*., p. 8.

In its replies to exceptions, Consumers notes that the MEC Coalition "agreed to not contest the PFD's recommendation that the Commission find that Consumers Energy's distribution cost allocation study complied with the requirements of the Case No. U-20134 Settlement Agreement." Consumers' replies to exceptions, p. 88. The company also disagrees with the MEC Coalition's recommendation "to further examine the contribution of each class and rate schedule to peak loads on the shared components of the distribution system in order to find a more refined approach to the distribution allocation." *Id*. Consumers states that its distribution cost allocation study is reasonable and supports its allocation of distribution costs and that "[c]lass peak is an industry standard that represents what drives distribution equipment investment and which uses an adequate level of detail between accounting, engineering, and load study data." *Id*., pp. 88-89. Finally, the company contends that additional studies may not provide improved allocation factors or if any value would be received by an additional study. Therefore, Consumers requests that the Commission adopt its non-coincident peak proposal and not require an additional study.

Consumers also replies to ABATE, stating that it addressed ABATE's contention in its initial brief and restates "that allocation of distribution costs at class peak by class voltage level better represents how the Company's system is designed." Consumers' replies to exceptions, p. 92. The company notes that the Staff agrees that class peaks should not be defined at class level, as suggested by ABATE, but by voltage level. Therefore, Consumers contends that the Commission should "maintain the calculation of class peaks for allocation of distribution costs at the class voltage level." *Id*.

In replies, the Staff states that ABATE mischaracterized its position. The Staff clarifies that it "opposed ABATE's proposed change to define class peaks at the rate class level instead of the sub-class level and does not propose modifying the current method." Staff's replies to exceptions, p. 51. The Staff contends that it did not argue that the status quo is flawed, rather it stated that if a change is to be made, it should be at the voltage level not the class level.

The MEC Coalition also replies that "ABATE's position runs counter to cost causation." MEC Coalition's replies to exception, p. 134. The MEC Coalition agrees that additional analysis is needed in the company's next rate case and avers that ABATE's proposal should be rejected.

In its replies to exceptions, ABATE contends that its proposal is the most reasonable and that Consumers agreed that it is an improvement on the company's plan**.** ABATE's replies to exceptions, pp. 5-6. ABATE also argues that the MEC Coalition's proposal for further examination is based upon an unsupported assertion. *Id*., p. 6.

The Commission first notes that there is no longer a dispute regarding whether the study set forth by the company is in compliance with the settlement agreement approved in the January 9 order. The dispute regarding potential deficiencies in the study, as discussed above, does not undermine this finding. As such, the Commission adopts the ALJ's findings and recommendation that Consumers has complied with the settlement agreement.

Next, the Commission addresses the MEC Coalition's claim that the ALJ's agreement with ABATE is unclear. In testimony, ABATE contended that the class peak method should be applied to aggregated demand by rate class, rather than for 40 separate rate classes and subclasses. *See*, 8 Tr 3006, 3015-3020; *see also*, PFD, pp. 390-392. In response, Consumers stated that "there could be a way to improve the calculation of class peaks that are coincident with the system voltage level that the different customer classes are served on;" however, Consumers contends that ABATE's proposal "does not accomplish this goal." 5 Tr 848. Consumers explained that "[w]hile ABATE's proposal is an improvement from the current process, it calculates class peaks at the rate class level, and not the class voltage level, which would better represent how the Company's system is designed . . . ." *Id*.; Consumers' initial brief, p. 459.

The Staff also disagreed with ABATE's proposal to define class peaks at the rate class level, stating that "[d]istribution classes are properly determined by voltage level, as is the case with the sub-classes in GPD, as not every customer uses the same parts of the distribution system. Classes are generally defined by the nature of the service provided, and in general voltage-level for distribution achieves this." 8 Tr 4638; Staff's initial brief, p. 179.

In their replies to exceptions, Consumers and the Staff reiterate the same arguments set forth in testimony and briefing.

The Commission finds that a review of the record shows that the company and the Staff object to ABATE's proposal because it improperly calculates class peaks at the rate class level. The Commission finds the Staff's and Consumers' arguments persuasive and concludes that the calculation of class peaks for allocation of distribution costs should be maintained at the class voltage level.

B. Rate Design and Tariff Issues

The company set forth several recommendations based upon its review and assessment of rate design issues. *See*, 4 Tr 559-560. The ALJ addressed many of the disputed issues separately in subsections, as the Commission has below.

Notwithstanding the above, the Staff raised several issues on exceptions which it contends the ALJ did not address in the PFD. First, the Staff indicates that the ALJ did not address the company's proposal to separate transmission expenses and production expenses in rate design. The Staff states that Consumers' "proposal will make visible for customers its approach for recovering both transmission and production expenses in rates and provide more detail and insight into production rates recommended for compensating [DG] customers." Staff's exceptions, p. 8.

The Staff does not oppose the company's proposal and indicates that no other parties objected to the proposal.

The Commission agrees with the Staff and finds that the company's proposal to separate transmission and production expenses in rate design should be approved.

The Staff also contends that the ALJ did not address the termination of the electric credit, which was established in Case No. U-20309 "to reduce customer rates to reflect the amortization of excess deferred federal income taxes." Staff's exceptions, p. 8. The Staff agrees with Consumers that the credit was to be in place until the establishment of new rates in the company's next general rate case, which is the instant case. As such, the Staff recommends that the Commission approve Consumers' proposal to incorporate the electric credit from Case No. U-20309 into base rates.

As set forth by the Staff, in the September 26, 2019 order in Case No. U-20309, the Commission approved a credit to be applied "in the interim period between the final order in the instant case and the establishment of new rates in the company's next general electric rate case." September 26, 2019 order in Case No. U-20309, p. 18. The Commission agrees that because this is Consumers' next general electric rate case, as described by the September 26, 2019 order in Case No. U-20309, the credit shall be incorporated into base rates.

1. Adjustments to the Cost of Service Study

The ALJ noted that Consumers recommended several adjustments to the assignment of costs across the various rate classes and schedules, which it argued were standard and consistent with prior electric rate cases:

> (1) reallocation of DR credits recovered through base rate [sic] to reflect the reduced capacity requirements of these programs; (2) capacity costs are assigned to Rate EIP to reflect the fact that a portion of EIP load is firm; (3) an adjustment to reflect the difference between the market cost of production capacity and the embedded cost of capacity in the COSS applied to Rate GSG-2; (4) additional

> adjustments for production energy and transmission costs for Rate GSG-2; (5) a correction for an over-allocation of substation costs for voltage levels 1 and 2 in the COSS; (6) a transfer of delivery costs between Rates LED and GUL in the streetlighting class; and (7) an adjustment for RSC and RIA credits.[38]

PFD, pp. 393-394; s*ee also*, 4 Tr 566-568.

In exceptions, the Staff indicates that the ALJ did not address Consumers' adjustment to assign capacity costs to the large industrial critical-peak rate, Rate EIP. The Staff notes that:

> [b]ecause Rate EIP is an interruptible resource, it is excluded from the allocation of production capacity costs in the COSS, but unlike other interruptible services, the Company's COSS does not differentiate between firm and interruptible load for Rate EIP since these customers can buy through the events. This results in no production capacity costs being assigned to Rate EIP in the COSS, and therefore, an adjustment needs to be made.

Staff's exceptions, p. 11 (citing 4 Tr 567). The Staff recommends that the Commission approve the proposed adjustment noting that, "[t]his rate is not being allocated these costs in the Company's COSS but is contributing to them." Staff's exceptions, p. 12 (citing 8 Tr 4701-4702).

The Commission finds that the Staff's proposed adjustment is reflected on Exhibit S-6, Schedule 2.1, Line 3, and is supported on the record. The Commission further concludes that the Staff's proposed adjustment is reasonable and prudent and should be adopted.

2. Adjustments to Production Costs Collection in Rate Design

The company recommended modifying its traditional approach of designing rates for the collection of production costs. Consumers explained the two changes to the method going forward:

> The first change involves using only the actual real-time Locational Marginal Price ("LMP") from the years 2014 to 2019 to calculate the energy charge spreads for the various TOU [time-of-use] rates. This change will avoid any underrepresenting of expected time differential in marginal energy prices that will be observed in 2021. *Id*. In addition, Mr. Miller explained the second change would "design the production capacity portion of rates to collect the portion of fixed plant costs in each period based on the expectation of serving customer demand during the time

[38] The RSC and RIA credits are addressed above in Section VI.J.

> based on the latest hourly load study for each class (MISO Cost of New Entry) and allocated production capacity in the COSS." 4 TR 569.

Consumers' initial brief, p. 470. The Staff did not oppose the company's recommended changes and no other party raised objections. *See*, Staff's initial brief, pp. 181-182.

The ALJ agreed with Consumers' modifications, noting that there was no opposition to the proposal, and recommended that it be approved. PFD, p. 394.

No exceptions were filed on this issue and, therefore, the Commission finds that the ALJ's findings and conclusions should be adopted.

3. Residential Rates

Consumers proposed maintaining the currently approved residential rate design with the exception of four modifications as follows: (1) increasing the critical peak price charge and peak-time rebate credit, which is assessed during peak events, from \$0.95 per kWh to \$1.00 per kWh; (2) adding a LIAC charge of \$30.00 per month for 4,200 of its residential customers; (3) gradually increasing the residential system access fee from \$7.50 to \$8.50 per month; and (4) improving consistency in the TOU charges assessed to residential customers across the residential rates.[39] *See*, 4 Tr 570-571.

The Staff recommended that the Commission decline to approve the peak time rewards (PTR) program and associated tariff. The Staff raised concerns about the PTR program which, in contrast to the critical peak pricing (CPP) program, only encourages reduction during the critical peak, does not allow the customer to know the impact of its usage reduction until after the critical event has passed, and offers less per customer kW savings compared to the CPP program. *See,*

[39] The addition of a LIAC charge is addressed in Section VI.J. above, the customer charge increase is addressed in Section VIII.A.1.e. above, and the TOU is further discussed in Section VIII.B. below.

8 Tr 4648-4649. In response, Consumers argued that the PTR program is "a critical component of its overall demand portfolio . . . ." 3 Tr 254-255.

The ALJ found the Staff's position to be persuasive and concluded that the PTR program should be discontinued. The ALJ agreed with the Staff "that the baseline the company calculates for each customer, upon which to determine the reward, is opaque" and that the PTR program is not revenue neutral. PFD, p. 396.

In exceptions, Consumers argues that its PTR DR option should not be discontinued as recommended by the ALJ. The company states that its dynamic peak pricing DR program includes two pricing options, the CPP "which replaces the participant's standard on-peak energy charge with a much higher critical peak energy charge in exchange for lower off-peak rates" and PTR "which offers customers a payment for reducing their energy usage during peak events." Consumers' exceptions, p. 249. The company reiterates that the only change it proposed in this proceeding was to increase the credit from $0.95 to $1.00 per kWh "to simplify communication and outreach to customers." *Id*. (citing 3 Tr 227-228). Consumers argues that it has established aggressive DR goals and that "PTR is an important option in the Company's overall cost-effective DR portfolio" and that its "overall DR program should not be limited to only those DR programs that are expected to provide the highest demand savings." *Id*., p. 250.

In response to the ALJ's determination that the PTR baseline is opaque and not revenue neutral, the company argues that neither of these concerns require the PTR program to be discontinued. Consumers reiterates that it "conducted internal analysis and worked with its third-party evaluator, Cadmus, to design and test the accuracy of the baseline calculation" and that "it is not necessary for PTR customers to know their specific kWh baseline." *Id*., p. 251.

In reply, the Staff asserts that the "CPP and PTR provisions both attempt to produce DR behavior from the same basic customer" but the Staff contends that "the CPP is superior." Staff's replies to exceptions, p. 47 (citing Staff's initial brief, pp. 187-189). The Staff reiterates its position that the PTR provision lacks clarity and that "when a PTR customer looks at their monthly bill it will be impossible to tell whether bill savings for DR behaviors are the result of the actual load shift or from a faulty baseline estimate." *Id*., p. 48.

The Commission agrees with Consumers that the PTR program is a reasonable option as part of the company's overall DR portfolio, particularly as it implements TOU rates. Therefore, the Commission declines to discontinue the PTR program at this time. The Commission recognizes the Staff's concerns and finds that, going forward, as the company is developing additional demand-side programs, the Commission would like to see more transparency in costs and savings for customers participating in those programs.

4. General Service Secondary and Primary Rates

Consumers proposed four changes to the company's secondary and primary rates as follows: (1) the closure of the company's General Service Secondary Rate (Rate GS) and Rate GP to new customers; (2) adding an interruptible provision to Rate GSTU and General Service Secondary Demand Rate (Rate GSD); (3) aligning delivery charges which are assessed under Rates GSTU and GSD; and (4) updating the power factor adjustment calculation under Rate GSD. *See*, 4 Tr 572.

a. Closure of General Service Secondary Rate and General Service Primary Rate

Consumers contended that the first proposed change, the closure of Rates GS and GP to new business, is appropriate given that "[t]he industry is moving away from the flat energy rate design used by many utilities today toward more advanced and individualized rate designs—such as TOU, demand-based, and subscription-based bills." 4 Tr 572. The Staff argued that Rate GS should not be closed to new customers, and that Rate GP should remain open to EV charging customers only until 2025.

The ALJ concluded "that the company should continue to evaluate the transition of small commercial and industrial customer[s] to TOU rates and should maintain rate GS open in the meantime." PFD, p. 398.

While no party excepts to the ALJ's conclusion to keep Rate GS open, the Staff argues that the ALJ "did not make a recommendation concerning the Company's proposal to close Rate GP to new business." Staff's exceptions, p. 10. The Staff reiterates its position that it is not opposed to the closure of Rate GP, apart from EV charging. The Staff contends that, to maintain crossing points, large amounts of money have been moved from Rate GPD to Rate GP in prior rate cases. The Staff notes that "the electric industry is moving away from flat energy rate designs and towards time-of-use and demand-based rate designs for large customers" and that the company currently offers rates which "will provide proper price signals to these larger customers." *Id.*, pp. 10-11 (citing 8 Tr 4701). The Staff also disputes the ALJ's finding that it did not oppose the closure of Rate GP given the Staff's recommendation for Rate GP to remain open to EV charging customers only until 2025. Staff's exceptions, p. 21.

The Commission finds that, at least for now, the ALJ properly recommended that Rate GS remain open to new customers while Consumers "continue[s] to evaluate the transition of small commercial and industrial customer[s] to TOU rates." PFD, p. 398. The ALJ noted on page 398, footnote 1246, that the Staff did not oppose the company's proposal to close Rate GP but did not make a recommendation on the matter. The Commission finds that this footnote is in error because the Staff opposed the closure of Rate GP with respect to EV customers. *See*, Staff's initial brief, p. 206. The Staff's recommendation is supported, and the Commission finds that Rate GP shall remain open for EV charging customers only until 2025, as recommended by the Staff.

b. Interruptible Credit

Regarding the company's second proposed change to add an interruptible provision to the Rates GTSU and GSD, the Staff argued that the interruptible credit should be applied on demand rather than on energy with respect to Rate GSD. *See*, 8 Tr 4651.

The ALJ found that "[t]he company did not appear to dispute this recommendation in its briefs; therefore, Staff's recommendation should be approved." PFD, p. 397.

In exceptions, Consumers states that its "proposed interruptible credit was designed as an energy credit, rather than a demand credit, for both rates." Consumers' exceptions, p. 231. The company agrees with the ALJ that it did not dispute the Staff's recommendation for Rate GSD. However, Consumers states that the Staff did not recommend the same for the Rate GSTU, and the ALJ's recommendation to grant an interruptible credit based on demand for Rate GSTU was in error. *Id*., p. 232.

The Staff also excepts, arguing that it recommended the proposed interruptible credit for Rate GSD to be calculated as a demand credit but did not recommend the same treatment for the proposed Rate GSTU credit. The Staff states that "[c]ustomers on Rate GSTU are not otherwise subject to demand charges, so issuing them a demand credit may cause some confusion." Staff's exceptions, p. 16.

The Commission has reviewed the record and finds that the Staff's proposal is only applicable to Rate GSD. *See*, 8 Tr 4651. The ALJ properly found that the company did not dispute the Staff's proposal; however, on exception, the parties seek clarification that the demand credit is only applicable to Rate GSD and not Rate GSTU. The Commission adopts the Staff's undisputed contention that the interruptible credit should be applied on demand rather than on energy with respect to Rate GSD only.

In addition, ABATE argues in exceptions that the ALJ failed to "explicitly address or make a recommendation regarding ABATE's proposal for increasing the amount of GI [Interruptible Service] credits." ABATE's exceptions, p. 9 (citing ABATE's initial brief, pp. 25-26; ABATE's reply brief, pp. 12-13). ABATE further argues that its proposal to increase the credits should be adopted "to further incentivize customer solutions to address demand issues." *Id*.

In reply, the Staff agrees that ABATE's proposal was not addressed by the ALJ. However, the Staff contends that "the currently approved GI credits are adequate to spur enrollment in DR rates while balancing costs to all ratepayers" and that the Commission should not approve an increase in the GI credit. Staff's replies to exceptions, p. 49.

The Commission finds that ABATE proposed to increase the credit for the GI provision from $7.00 to $9.00 per summer kW and from $6.00 to $7.70 per winter kW. *See*, 8 Tr 3025. The company relied upon 75% of cost of new entry (CONE) whereas ABATE's proposal is based on full CONE less line losses. The Commission agrees with the Staff that the increase in the GI credit is not necessary as the record reflects that the present levels are providing sufficient incentive to encourage customer participation in the GI program, given recent increases in MW served under the provision. *See*, 8 Tr 4655. Therefore, the Commission declines to adopt ABATE's proposal to increase GI provision credits.

c. Demand Charges

The Staff opposed the company's proposal to add a peak demand charge to Rate GSTU, arguing that "[d]emand charges for small customers can be problematic and can result in customers being charged for costs they are not contributing to." 8 Tr 4699.

The ALJ found that the Staff's concerns have merit and rejected the company's proposal to add a demand charge to Rate GSTU. PFD, p. 399.

Consumers takes exception and argues that it "believes it is important to send accurate price signals regarding the cost of delivering power to customers which are mostly fixed or demand-based costs, and having a consistent delivery-rate design structure across the individual rates within a class is appropriate." Consumers' exceptions, pp. 232-233 (citing 4 Tr 573). The company avers that the Staff included a peak demand charge in Exhibit S-6 and "[t]herefore, it is unclear whether Staff truly intended to reject the peak demand charge proposed by the Company for Rate GSTU." Consumers' exceptions, p. 233. Consumers contends that the Commission should approve the peak demand charge for Rate GSTU to ensure consistent rate design for Rates GSTU and GSD.

The Staff replies that it "was clear in its testimony and brief that Staff does not support adding a peak demand charge to rate GSTU" even though it made an error in its exhibit by inadvertently including a peak demand charge for Rate GSTU. Staff's replies to exceptions, p. 49.

As noted by the Staff, it made an error in Exhibit S-6. However, the Commission finds that it is clear that the Staff opposed the addition of a peak demand charge to Rate GSTU. *See*, 8 Tr 4698-4699. Furthermore, the Commission agrees that demand charges can be problematic for small customers, potentially resulting in charging customers for costs they are not contributing to. *Id.*, p. 4699. Therefore, the Commission finds that the ALJ's recommendation is reasonable and supported by the record and should be adopted.

d. Power Factor Adjustment

In exceptions, the Staff notes that the ALJ did not address Consumers' proposal to update the Rate GSD power factor adjustment. Citing the company's position, the Staff states that a more transparent power factor adjustment schedule will be provided by aligning the power factor adjustment across the company's business rate options, and that Consumers "will encourage GSD customers to improve their power factor beyond 90% by now offering a credit and that it will also reduce the inconsistency between its business rates." Staff's exceptions, p. 10. The Staff reiterates that it does not object to the proposal and that no other parties provided comment on GSD power factor adjustment.

The Commission, having reviewed the record, finds that the parties did not dispute Consumers' proposal to update the Rate GSD power factor adjustment and finds that the proposal should be approved.

5. Streetlighting Rates

Consumers proposed two changes to the streetlighting rate class as follows: (1) replacing the existing LED rate (Rate GU-XL) with a simpler, more transparent rate design; and (2) adding a conversion credit for municipal streetlighting customers who, prior to the adoption of the company's LED replacement program, paid to convert from standard streetlighting to LED. 4 Tr 574. The Staff supported the company's proposal, while MAUI recommended a unified tariff for unmetered streetlighting. 8 Tr 4016-4017.

The ALJ found that Consumers did not oppose the recommendation to develop a unified tariff for its unmetered streetlighting which combines Rates GUL and GU-XL. Therefore, the ALJ recommended that the Commission require Consumers to provide a unified tariff in the company's next general rate case. PFD, p. 399.

No exceptions were filed on this issue and the Commission finds that the company shall file a unified tariff combining Rates GUL and GU-XL in the company's next general rate case, as recommended by the ALJ.

C. Other Tariff Issues

The ALJ found that the majority of the changes to the company's proposed tariffs were unopposed or agreed to by the parties and that the remaining disputed issues pertained to Consumers' proposed DG tariff, its low-income program, and contributions in aid of construction (CIAC). The issues pertaining to the low-income program are addressed above, in Section VI.J., and the remaining issues are discussed in the sections below.

1. Distributed Generation Tariff

Consumers submitted a proposed DG tariff it contends is consistent with MCL 460.6a(1) and MCL 460.1173(1). *See*, Exhibit A-16.

a. Program Cap

MCL 460.1173(3) states that: "An electric utility . . . is not required to allow for a distributed generation program that is greater than 1% of its average in-state peak load for the preceding 5 calendar years." According to the statute, the 1% limit shall be allocated at no more than 0.5% for customers "with an eligible electric generator capable of generating 20 kilowatts or less" (category 1), no more than 0.25% for customers with generators capable of generating more than 20 kW but not more than 150 kW (category 2), and no more than 0.25% for customers with methane digesters capable of generating more than 150 kW (category 3). *Id*.

The Staff stated that the program size percentages are "soft caps" because enrollment beyond the caps is not prohibited and that Consumers can increase the caps if it so chooses. The Staff recommended that Consumers voluntarily raise the cap to 2% given the forecasts that the caps could be reached for category 1 as soon as October 2020, and for category 2 by the end of 2021. 8 Tr 4815. Additionally, the Staff acknowledged that once the caps are reached, the company will still be able to continue to purchase power from customers under the PURPA standard offer rate or through an energy-only contract. *Id*. However, the Staff expressed concern that, once the DG program caps have been reached, customers installing solar must sign a contract with very different pricing with the company. The Staff contends that the process is inefficient because these contracts must be approved by the Commission. 8 Tr 4814-4817. In addition, many intervenors argued that the soft cap should be lifted, echoing the Staff's concerns, as well as noting pending legislation. The intervenors also claimed that the 1% cap applies only to net metering and not DG.

EIBC/IEI argued that the measurement of system size, which affects the cap, is not defined under MCL 460.1173. EIBC/IEI noted that "the generation capability of a system can be measured in two places: at the output of direct current from the solar panels to the inverter, which is generally referred to as kWDC [kilowatt direct current], and at the output of alternating current from the inverter to the grid interconnection, which is generally referred to as kWAC [kilowatt alternating current]. 8 Tr 4501. EIBC/IEI contended that the system should be measured in terms of kWAC for purposes of measuring the system size against the cap, rather than the kWDC, as the company has done. *Id*. The Staff and the company generally agreed with EIBC/IEI's recommendation. *See*, Staff's reply brief, p. 51; 6 Tr 1587-1588.

The ALJ concluded that, under the statute, Consumers is not required to lift the 1% cap and merely because other utilities have voluntarily raised the cap, does not mean that the Commission has the authority to require Consumers to lift the cap. PFD, p. 406. Nevertheless, she determined that "measurement of program size should be in kWAC rather than the current installed capacity measured in kWDC" and recommended that the "Commission direct the company to recalculate the amount of capacity subscribed and provide a report on the available capacity under the 1% cap to the Commission within 60 days of the date of this order." PFD, pp. 406-407.

In exceptions, EIBC/IEI contends that "[n]o party to this proceeding requested or recommended that the Commission require or 'direct' Consumers to increase the cap on DG." EIBC/IEI's exceptions, p. 8. Rather, EIBC/IEI argues that the Commission has the authority to recommend that Consumers lift the cap and requests "that the Commission affirmatively find that Consumers should voluntarily lift the 1% soft cap, if it otherwise approves any portion of Consumers' requested DG tariff in this proceeding." *Id.*

Grand Rapids excepts, arguing that the company cannot limit participation in the DG tariff at 1% because such a limitation is in conflict with Michigan law under the rules of statutory interpretation and does not result in cost-of-service-based rates. Grand Rapids' exceptions, pp. 4-8. Grand Rapids contends that the Commission can lift the 1% cap because it is in conflict with the requirement that rates be cost based and is against the legislative intent. Grand Rapids states that the application of the cap in the DG tariff would create a subclass of customers who will be charged differently "simply because they did not sign up for the program sooner." *Id.*, p. 7. Grand Rapids further argues that "Consumers' customers are likely to avoid investments in clean and renewable energy through distributed generation given that beginning October 2021, many are unlikely to receive cost-of-service-based compensation for their contributions to the grid." *Id.*, p. 8. Grand Rapids argues that the statutory language must be read in the context of the whole act and that the Commission should conclude that "the statute should be read to apply the 1% cap only to the existing net-metering program, which is not a cost-of-service rate." Grand Rapids' exceptions, p. 9.

In reply to EIBC/IEI, Consumers states that "[i]t is not necessary for the Company to voluntarily lift the statutory DG cap in order to receive approval of the Company's proposed DG tariff." Consumers' replies to exceptions, p. 102.

Consumers also replies that Grand Rapids is advancing, for the first time on record, its contention that the 1% cap only applies to legacy net metering customers. The company argues that Grand Rapids improperly attempts to utilize the principles of statutory construction to support its argument but "places virtually no emphasis on the paramount rule of statutory construction," which is to look at the plain language of the statute to give effect to the Legislature's intent. *Id*., pp. 107-108. Consumers states that "[t]he plain language of the DG statute clearly and unambiguously imposes a cap on customer participation in each utility's DG program equal to 1% of the utility's average in-state peak load for the preceding five calendar years." *Id*., pp. 108-109. Consumers avers that Grand Rapids attempts to evade the plain language of the statute by arguing that there is a conflict between MCL 460.1173(3) and MCL 460.11, which the company states is "plainly incorrect." *Id*., p. 109. Further, Consumers states that in a properly structured DG tariff, there would be no conflict between the provisions "because even non-participants would be receiving cost-based rates as required by MCL 460.11 . . . ." *Id*., p. 110. Consumers argues that Grand Rapids' interpretation also violates another principle of statutory construction, that each provision should be interpreted to avoid conflict, if possible, and they must be construed to give full force and effect to each provision. *Id*.

The Commission finds that no party filed exceptions to the ALJ's determination that "measurement of program size should be in kWAC rather than the current installed capacity measured in kWDC" and the ALJ's recommendation that the "Commission direct the company to recalculate the amount of capacity subscribed and provide a report on the available capacity under the 1% cap to the Commission within 60 days of the date of this order." PFD, pp. 406-407. The Commission finds that the ALJ's findings and conclusions are reasonable and supported by the record and that they should be adopted.

As previously noted, MCL 460.1173(3) states that: "An electric utility . . . is not required to allow for a distributed generation program that is greater than 1% of its average in-state peak load for the preceding 5 calendar years." The Commission is not persuaded by Grand Rapids' statutory analysis argument. The primary goal of statutory interpretation is to give effect to the Legislature's intent "focusing first on the statute's plain language" and "[w]hen a statute's language is unambiguous, the Legislature must have intended the meaning clearly expressed, and the statute must be enforced as written." *Kemp v Farm Bureau Gen Ins Co of Mich*, 500 Mich 245, 252; 901 NW2d 534, 538-539 (2017) (internal citations omitted).

The Commission finds that MCL 460.1173(3) is unambiguous and clearly applies to DG programs, as stated in the plain language of the statute. Grand Rapids' attempt to introduce a conflict between this provision and MCL 460.11 is tenuous at best and is not harmonious with the requirement to construe statutes to avoid conflict, if possible. *See*, *In re AGD*, 327 Mich App 332, 344; 933 NW2d 751 (2019) (holding "[i]f statutes lend themselves to a construction that avoids conflict, that construction should control."). The Commission declines to read a conflict into the statutes in an attempt to override the plain meaning of each. Overall, the Commission is not persuaded that the Legislature intended for MCL 460.1173(3) to apply only to legacy net metering programs when the provision's plain language references "a distributed generation program." Therefore, the Commission rejects Grand Rapids' argument that DG participation cannot be limited by the company. The Commission concludes that it does not have the authority in a rate case proceeding to unilaterally require Consumers, or any other electric utility, to increase the 1% cap on DG participation given the plain language of the statute.

The Commission notes, however, that in Consumers' replies to exceptions, the company stated that:

> following review of the DG tariff approved in this proceeding, including the compensation for DG customers, the Company will consider agreeing to voluntarily raise its DG program limit from the 1% limit provided for in MCL 460.1173(3) to 2% of the average in-state peak load for the preceding five calendar years. This voluntary increase in the DG program limit is expected to be effective upon the effective date of the DG tariff. The Company will inform the Commission and customers of any voluntary change in the DG program limit. The Company reserves the right to maintain the statutory limit of 1% of the Company's average in-state peak load for the preceding five calendar years.

Consumers' replies to exceptions, pp. 102-103. Therefore, Consumers may, at its discretion, voluntarily increase the level of participation in its DG program cap to 2%.

EIBC/IEI argued that it is unclear, pursuant to MCL 460.1173, whether the DG program "is to be measured by the sum of sizes or by the average output of such systems at the time of the utility's in-state peak load." 8 Tr 4502. Thus, EIBC/IEI proposed that the "[a]verage output at the time of Consumers' in-state peak demand could be closely approximated by using MISO's system capacity credit method." *Id.*, p. 4503. Consumers responded, arguing that EIBC/IEI's proposal is inconsistent with MCL 460.1173 "because it would result in a cap based on the five year average in-state peak for gross bundled load, which . . . is different than the forecast peak load coincident to MISO . . . ." Consumers' initial brief, p. 500 (citing 6 Tr 1588-1589).

The ALJ agreed with the company and found that MCL 460.1173 does not reference the MISO capacity method. She stated that "the VGP [voluntary green pricing] programs under MCL 460.1061 do not specify program size limits at all, thus, EIBC/IEI's claim regarding Consumers' use of ZRCs in that program is inapposite." PFD, p. 408. The ALJ also concluded that Consumers' system peak is not coincident with the MISO peak, and therefore, the use of "the MISO method for assigning capacity credits is inappropriate." *Id.*

No exceptions were filed on this issue. The Commission finds that the ALJ's findings and conclusions are reasonable and supported on the record and should be adopted.

b. Outflow Credit

Consumers' DG tariff includes an outflow credit consistent with MCL 460.6a(14), which the company argued is superior to the former net metering approach, where inflows and outflows were netted on a monthly basis, and the outflow credit equaled the inflow cost. Consumers contends that its DG program tariff is substantially similar to the model tariff contained in Attachment A to the April 18, 2018 order in Case No. U-18383 (April 18 order) and DTE Electric's DG program tariff approved in the May 2 order. The company asserted that the inflow/outflow method is better aligned with the principle of cost causation and reduces the subsidy provided to DG customers by non-DG customers. Consumers' initial brief, pp. 470-484.

JCEO objected to numerous aspects of the proposed DG program tariff and argued that Consumers offered no COS, "empirical data, analysis or other quantitative justification in support of either its proposed Inflow charge or Outflow credit." JCEO's initial brief, p. 12. JCEO also argued that the Brattle Report contains numerous errors and was erroneously used to suggest that the cost to serve DG customers is higher than the cost to serve non-DG customers. *See*, *id*., pp. 23-33.

The ALJ concluded that "the preponderance of the evidence demonstrates that DG customers do <u>not</u> cost more to serve than non-DG customers and may in fact cost less." PFD, p. 412 (emphasis in original). The ALJ found that, even though there were some issues with JCEO's analysis, it was more complete and persuasive than the company's Brattle Report.

Consumers takes exception to the ALJ's conclusion that DG customers may cost less to serve than non-DG customers. The company argues that the ALJ did not adequately consider its position, and "appears to only consider the evidence presented by the JCEO." Consumers' exceptions, p. 234. Consumers contends that the Brattle Group's study was based on "the best data available at the time the study was performed." Consumers' exceptions, p. 235 (citing 5 Tr 849). The company asserts that the alleged errors and omissions in the Brattle Group study, claimed by JCEO, are based upon a lack of understanding by JCEO's witness. Consumers states that, "[t]he Brattle Report results clearly showed that the Company's DG customers cost more to serve than non-DG customers." Consumers' exceptions, pp. 235-238.

In reply, the Attorney General argues that "the ALJ provided an in depth review of the record in reaching her conclusion" on the deficiencies of the Brattle Report and she correctly concluded that DG customers likely do not cost more to serve than non-DG customers. Attorney General's replies to exceptions, p. 62.

Grand Rapids replies that the evidence does not demonstrate, as Consumers contends, that DG customers are more expensive to serve than non-DG customers. Grand Rapids avers that the ALJ properly considered the Brattle Group's report and she "correctly concluded that Company witness Aponte's testimony failed to reconcile the report's considerable flaws." Grand Rapids' replies to exceptions, p. 4 (citing PFD, p. 412).

Next, JCEO argued that Consumers and the Staff failed to provide a quantitative analysis of the costs and benefits of DG. JCEO's initial brief, pp. 18-19. JCEO preformed its own analysis, and set forth an outflow credit and adder, which the company counters is excessive because it is substantially higher than the market-based costs of utility scale solar. 8 Tr 4251; 4 Tr 594. JCEO responded that it is "inappropriate to use the cost of solar resources procured through competitive solicitations as a proxy for the value of DG Outflow . . . ." JCEO's reply brief, p. 10.

The ALJ concluded that "Consumers largely relied on assumptions and findings from other proceedings . . . without undertaking a comprehensive analysis of DG on its own system in this case." PFD, p. 415. The ALJ also found that JCEO's analysis had significant shortcomings including "the large differential between the cost of solar energy procured through competitive bidding under the company's IRP, and the calculated cost of solar energy purchased from small DGs." *Id*. The ALJ stated that "[t]he only way to address the conflicting positions is to undertake a more comprehensive assessment of the costs and benefits of DG outside of a rate case" and, therefore recommended that the Commission "maintain the status quo until a VOS [value of solar] analysis is completed." PFD, pp. 415-416.

Consumers takes exception, stating that the ALJ's recommendation fails to consider the company's evidence and

> failed to analyze the Brattle Report in this proceeding, as addressed above, which provided support for the Company's proposed outflow credit; provided no analysis of the authority under MCL 460.1177(4); no analysis of the Commission's findings in recent DTE proceedings within which substantially similar DG tariffs were presented and approved; and no explanation as to why the Company's proposed outflow credit in this proceeding should not be approved until the conclusion of a VOS workgroup, in the event the Commission finds such a workgroup should even be conducted.

Consumers' exceptions, p. 239. Consumers reiterates that its proposed DG program tariff complies with MCL 460.6a(14) and the April 18 order, that the inflow/outflow method is superior to the net metering program, and is better aligned with cost-based principles. *See*, Consumers' exceptions, p. 239.

Consumers also contends that the ALJ's recommendation fails to consider MCL 460.1177(4), and that the company properly proposes to compensate "DG customers at power supply less transmission, as set forth in subpart (b) of MCL 460.1177(4)." Consumers' exceptions, p. 241. In addition, Consumers asserts that its proposal "properly compensates DG customers for the excess power placed on the Company's distribution system in a billing period and, at the same time, removes subsidies previously in place that inappropriately compensated DG customers for transmission in the outflow credit, which is a service the DG customer does not provide." *Id*. Consumers reiterates that its DG program tariff is substantially similar to the DG tariff recently approved in the May 8 order, which reconfirms "that an outflow credit based on power supply less transmission, as proposed by the Company in this proceeding, remains a just and reasonable approach to crediting DG customers' [sic] for outflow today." Consumers' exceptions, p. 243. Consumers also avers that, even if the Commission adopts the ALJ's recommendation on a VOS workgroup, it should not adopt her recommendation to maintain the status quo until the conclusion of the workgroup process. *Id.*, pp. 243-244.

In exceptions, the Staff states that the ALJ failed to fully consider the Staff's position relating to the outflow credit and its many concerns with JCEO's analysis of the DG outflow compensation. The Staff reiterates that JCEO's calculation treats DG customers as a separate class, while also recommending that they not be a separate class. The Staff also disputes JCEO's claim that outflow reduces load and that outflow offsets costs caused by inflow. Staff's exceptions, pp. 22-24 (citing Staff's initial brief, pp. 208-209).

In addition, the Staff asserts that the ALJ did not address its responses to JCEO's criticisms of the proposed tariffed rates. Specifically, the Staff contends that the inflow and outflow rates are cost based because they are calculated based on the COSS, the proposed tariffed rates are equitable because they are the same for all customers in the class, and that the tariffed rates are just and reasonable because they are based upon the COSS, which was not disputed as being unjust or unreasonable. Staff's exceptions, pp. 24-25. The Staff states that performing a separate COSS to examine costs to serve DG customers "would require treating DG customers as a separate class, which Staff has been firmly against" and should be rejected. *Id*., p. 25.

Finally, the Staff contends that the ALJ did not consider its argument as to why the full retail rate should not be used as the DG outflow credit. The Staff reiterates that JCEO's study to support an outflow credit that exceeds the full retail rate was flawed and that using the same flawed study to support an outflow credit at the full retail rate is not supported. *Id*., p. 26 (quoting Staff's reply brief, pp. 42-43). The Staff argues that distribution system benefits have not been quantified on the record, and that the Commission should not presume that DG customers fully offset all of the distribution expenses by setting the outflow credit at the full retail rate. *Id*.

In their exceptions, EIBC/IEI request that the Commission clarify the ALJ's recommendation to maintain the status quo. Specifically, EIBC/IEI state that "an outflow credit for the DG tariff will be established at the current 'status quo' rate of the full retail rate until a VOS analysis is completed." EIBC/IEI's exceptions, p. 4.

JCEO similarly requests that the Commission clarify the ALJ's recommendation to maintain the status quo. JCEO states that the Commission should clarify that the status quo is to compensate DG customers at the full retail rate. JCEO's exceptions, p. 10.

In exceptions, Grand Rapids contends that the ALJ's recommendation "is the best approximation available now for a [DG] tariff based on cost-of-service." Grand Rapids' exceptions, pp. 2-3.

In reply, Consumers contends that the Commission should reject EIBC/IEI's and JCEO's requests to clarify that "maintaining the status quo" means to compensate DG customers at the full retail rate. Consumers reiterates that its proposed DG tariff is reasonable and that the Commission should "approve the Company's proposal to set the compensation credit for DG customers at power supply less transmission." Consumers' replies to exceptions, pp. 99-100.

Contrary to Consumers' exceptions, the Attorney General argues that the ALJ made a detailed analysis of the arguments in making her recommendation to maintain the status quo until a VOS study workgroup is completed. Attorney General's replies to exceptions, pp. 63-64.

In reply to the Staff, Grand Rapids asserts that the Staff misconstrues its argument. Grand Rapids avers that the DG tariff is unjust and unreasonable "because it excluded from the outflow credit the cost-of-service-based transmission and distribution charges that distributed generation customers allow Consumers to avoid." Grand Rapids' replies to exceptions, p. 2. Grand Rapids contends that this argument is valid "even if the City did not present evidence challenging the underlying Cost of Service Study." *Id*. In response to Consumers, Grand Rapids argues that the company's "erroneous and persistent assertion that the provisions of MCL 460.1174(4) guide the determination of equitable cost of service has been repeatedly rejected by the Commission." *Id*., p. 4 (citing May 2, 2019 order in Case No. U-18383).

EIBC/IEI also responds to Consumers, arguing that the ALJ clearly considered the company's arguments and discussed, at length, Consumers' responses to JCEO's contentions. Therefore, EIBC/IEI states that Consumers' exceptions are based upon "an inaccurate reading of the PFD." EIBC/IEI's exceptions, p. 7. EIBC/IEI further notes its agreement with the ALJ that adopting the status quo for outflow compensation until a VOS study is completed is reasonable and supported.

In its replies to exceptions, JCEO asserts that Consumers' exception alleging that the ALJ failed to consider the Brattle Report is meritless as she "squarely addresses the Brattle Report at pages 409-412." JCEO's replies to exceptions, p. 7. JCEO also argues that the Commission has previously found that MCL 460.1177(4) only applies to modified net metering and not to inflow/outflow tariffs. In response to Consumers' claim that the Commission should approve its tariff because it mirrors the DG tariff approved for DTE Electric, JCEO states that "the PFD makes abundantly clear that 'rel[ying] on assumptions and findings from other proceedings, namely, the Commission's approval of DG tariffs for DTE Electric and other utilities, without undertaking a comprehensive analysis of DG on its own system' is not sufficient to secure Commission approval of the Company's proposal." *Id*., pp. 7-8.

In reply to the Staff, JCEO argues that the ALJ carefully considered the outflow credit, and contends that the company has not met its evidentiary burden to support the proposed outflow credit. *Id*., pp. 3-4. JCEO also asserts that the Staff misconstrues the ALJ's determination to compensate customers at the full retail rate as effectively leaving net metering in place until the completion of the VOS study. Instead, JCEO contends that the ALJ required an inflow/outflow tariff, which replaces net metering, and sets the outflow credit at the full retail rate on an interim basis. JCEO states that this "is entirely consistent with a transition towards cost-based compensation for DG customers, with Michigan law, and with the Commission's past orders with respect to DG Compensation." *Id*., p. 5.

In evaluating the statutory provisions enacted by the Legislature in 2016, the Commission's past determinations on the development and applicability of the inflow-outflow framework, and the extensive record in this case, the Commission disagrees with the ALJ's determination that JCEO's analysis justifies a rejection of the inflow-outflow methodology proposed by Consumers based directly on the framework approved in the April 18 order. As further discussed below in the context of the proposed VOS study, the Commission acknowledges the flaws and shortcomings associated with both the JCEO and Brattle Group studies, as well as the challenges and complexities inherent in determining an equitable cost of service for DG customers, due in part to the data limitations associated with the still relatively small pool of DG customers.

Notwithstanding, the Commission finds the ALJ’s recommendation to compensate DG customers at the full retail rate, while the Commission continues to evaluate these cost allocation and rate design issues, is not adequately supported by the record in this case, even if the full retail rate is branded as an outflow credit. As noted by the Staff, while DG systems may provide benefits such as reduced loading and line losses:

> none of these services was quantitatively determined in the instant case. JCEO is effectively suggesting in their brief that in the absence of determining the value of these distribution services, the Commission should compensate DG customers as if they fully offset all their distribution expenses. Staff disagrees. Staff instead recommends that since the quantitative value of these services has not been determined in the instant case that the presumed amount of distribution offset should be zero. In spite of JCEO’s protestations, no other party has a responsibility to support their position for them, and the specific analyses they wish had been conducted are not required to formulate a rate consistent with the law.

Staff’s reply brief, p. 43.

The Commission also finds that the company’s proposed DG tariff is consistent with prior Commission orders and DG designs approved for other companies. *See*, April 18 order; May 2, order; May 8 order. Although the ALJ cites the company’s reliance upon other proceedings as a detriment, the Commission nevertheless concludes that the consistency of Consumers’ proposal and application of methodologies previously analyzed and approved by the Commission is appropriate and ensures greater consistency for solar contractors and customers transitioning to more cost-based tariffs. Indeed, Consumers’ reliance in this case on the Commission’s prior approval of the inflow/outflow tariff structure is expected given the two-step process laid out in MCL 460.6a(14) for the Commission to “conduct a study on an appropriate tariff reflecting equitable cost of service for utility revenue requirements for customers who participate in a net metering program of distributed generation program” under 2008 PA 295, as amended, and that "[i]n any rate case filed after June 1, 2018, the commission shall approve such a tariff for inclusion in the rates of all customers participating" in such a distributed energy program. MCL 460.6a(14).

As noted by the Staff, the company's proposed DG tariff is an inflow/outflow tariff "with inflow being charged at the applicable base rate and outflow being credited at the power supply portion of the applicable rate, including PSCR but less transmission." 7 Tr 2864. The Commission further finds that, even though the Brattle Report is not without flaws, it provides support for the company's proposed tariff, which more closely aligns with cost-of-service-based rates than the continuation of net metering or other alternatives presented in this case. *See*, 7 Tr 2864-2865. The Commission, therefore, rejects the ALJ's recommendation and approves Consumers' proposed inflow/outflow DG tariff.

c. Value of Solar

As previously noted, JCEO recommended that the Commission direct the Staff to facilitate a VOS study, to be carried out by an independent third-party consultant, with the Staff coordinating with Consumers and interested stakeholders. JCEO's initial brief, p. 61. Consumers countered that JCEO's approach is not consistent with MCL 460.1173 or COS principles. Consumers' initial brief, pp. 488-489.

The ALJ stated that "[t]he Commission was clear that the Inflow/Outflow tariff approved in Case No. U-18383 was not the end of the inquiry, and that '[a]s the DG program evolves and more data becomes available the Commission will better be able to assess the cost <u>and benefit impacts</u> and conduct rate design consistent with COS principles." PFD, p. 419 (emphasis in original). Therefore, she concluded that it is reasonable to adopt JCEO's recommendation for a VOS analysis which will allow for the evaluation, and potential refinement, of the outflow credit. The ALJ further states that Consumers' concerns regarding the VOS study resulting in a tariff that is not consistent with COS principles can be addressed as part of the VOS study process.

"Accordingly, the ALJ recommends that the Commission direct Staff to convene a workgroup of interested stakeholders to develop a VOS-based outflow credit consistent with the requirements of MCL 460.6a(14), within 90 days of the date of the final order in this case." *Id*., p. 420.

In exceptions, Consumers argues that the ALJ did not explain what developments have occurred since the April 18 order which would support her recommendation for conducting a VOS workgroup. Consumers' exceptions, pp. 244-247. Referencing the May 8 order, the company contends that "the Commission found no significant updates or developments" as of May 2020. *Id*., p. 246. In addition, Consumers argues that:

> The Company recommends that the Commission reject the recommendation to conduct a VOS workgroup, for the reasons already provided, and find that the Company's proposed DG Tariff is reasonable. Further, in the event the Commission finds that a VOS workgroup should be conducted, the Company recommends that the Commission still approve the Company's proposed DG Tariff in this proceeding while any such workgroup is conducted. The evidence in this case supports the conclusion that the Company's DG Tariff, which is substantially similar to the tariff recently approved in Case No. U-20561 and currently in effect today, should be approved.

*Id*., p. 247.

The Staff takes exception, claiming that the ALJ failed to fully consider its arguments relating to a VOS workgroup. The Staff clarifies that it "recommends approving the Company's DG Tariff as proposed, rejecting the JCEO interim tariff, and is open to the possibility of a value of solar workgroup with caveats." Staff's exceptions, p. 21 (quoting Staff's initial brief, pp. 210-211). The Staff states that it has already satisfied the mandate pursuant to MCL 460.6a(14) to "conduct a study on an appropriate tariff reflecting equitable cost of service for utility customers who participate in a net metering program or distributed generation program." Staff's exceptions, p. 27 (citing the April 18 order). As such, the Staff objects to the ALJ's recommendation to conduct yet another study and effectively leave net metering in place.

The Attorney General replies that the ALJ's recommendation to conduct a VOS workgroup was reasonable and supported by the April 18 order, wherein the Commission found that that case was not the end of the inquiry. The Attorney General further states that the VOS issue is important to encourage DG in Michigan.

In reply, JCEO contends that Consumers' exceptions are contrary to the company's testimony relating to a VOS workgroup and that Consumers mischaracterizes the ALJ's conclusions. JCEO states that Consumers inaccurately suggests that the ALJ recommended maintaining a net metering approach and that she dismissed the inflow/outflow method. Rather, JCEO asserts that the ALJ adopted the inflow/outflow method with the outflow credit set at the full retail rate. JCEO's replies to exceptions, p. 9.

In its replies to exceptions, JCEO notes that the Staff states "that it is open to the possibility of a VOS workgroup, but raises arguments regarding whether and how the VOS workgroup should consider the societal externalities associated with distributed generation. Staff requests that the Commission consider those arguments in making its determination regarding a VOS workgroup." JCEO's replies to exceptions, p. 6. JCEO contends that Consumers raised similar arguments and that the ALJ considered those arguments in the PFD. JCEO asserts that the ALJ properly declined to "prematurely constrain the VOS workgroup." *Id.*, pp. 5-6.

Grand Rapids contends that societal values should be included in the VOS workgroup process and would assist the Commission in understanding the avoided environmental costs of solar energy. Grand Rapids states that, "[e]ven if Staff persists in its opinion that these societal costs cannot be incorporated into an outflow credit without action by the Legislature, the information gathered during a VOS analysis will at least assist Staff and the Commission in developing recommendations and information for updating IRP requirements." Grand Rapids' replies to exceptions, pp. 1-2. In response to Consumers, Grand Rapids references Case No. U-20162 and states that "the Commission explicitly anticipated that future cases would require a more comprehensive inquiry into the value of distributed solar" and "[t]hat later date has arrived . . . ." Grand Rapids' replies to exceptions, pp. 4-5.

The Commission recognizes the need to conduct a more comprehensive analysis of rate design options for evolving technologies including solar and other DERs. As noted in the Staff's MI Power Grid status report filed on October 15, 2020, in Case No. U-20645:

> On September 29, 2020, the Michigan Senate adopted Senate Resolution 142, which recognizes that "energy customers are adopting new and evolving technologies including customer-owned generation, energy storage, electric vehicles, and customer energy management capabilities" and encourages the Commission "to undertake a study on rate designs and options, including fixed system access and demand charges and rate design options that will account for the changing customer use of the grid due to the adoption of new energy technologies."

MI Power Grid status report, p. 22. The Commission envisions DERs (including solar) to be evaluated as part of the study referenced in Senate Resolution 142, which would include a kick-off meeting with stakeholders being invited to provide comments on the scope and structure of the study. With respect to the scope of the study, the Commission stresses the importance of examining both costs and benefits of DERs in the context of how customers with DERs use the grid now and into the future, and to vet different approaches to cost allocation and rate design to align with such usage. The Commission envisions working with a third-party to facilitate the execution and delivery of the study with opportunities for feedback in the kick-off meeting to define the study scope and structure. In addition, once the study is complete, the Commission would again seek comments from stakeholders. The study results would then flow into the Innovative Rate Design Offerings work area of the MI Power Grid initiative, as noted in the MI Power Grid Status report, to develop tariffs and rates representative of the cost and value of DERs as determined in the study. Therefore, the Commission directs the Staff to organize the kick-off meeting in the first quarter of 2021.

d. Other Distributed Generation Issues

Consumers proposed to consolidate the self-generation provisions of tariffs, contained in numerous rates, to proposed Rule C11.1. The company explained that:

> Rule C-11 is being modified to include Self-Generation and the Distributed Generation Program, in addition to the Net Metering Program. The Company's current Self-Generation is for customers with generator installations less than 550 kW. The language is currently found within the tariff of each individual eligible rate. Self-Generation is proposed to be Rule C-11.1 and will be located on Tariff Sheet No. C-58.00. The Company's current Net Metering Program has been moved from Rule C-11 to Rule C-11.2 and begins on Tariff Sheet No. C-58.20.

6 Tr 1620.

EIBC/IEI raised concerns that the company's new Rule C11.1 "would violate PURPA in that it denies that Consumers has an obligation to purchase energy 'as available' from a QF [qualified facility], as well as a requirement that a QF enter into a written contract with the Company, either a standard offer contract, or an energy-only contract." EIBC/IEI's initial brief, p. 25. Thus, EIBC/IEI contended that the Commission should reject the proposed Rule C11.1 or require the language contained therein to be modified.

The ALJ held that:

> Because the interconnection rules are in the process of an extensive update, interested parties have an opportunity to participate in the ongoing Distributed Generation and Legacy Net Metering Rules workgroup. In addition, concerns about Consumers' self-generation tariff, in the event the company refuses to connect a customer and purchase energy "as available," should be addressed in a complaint, or in Consumers' next PURPA avoided cost proceeding.

PFD, p. 420.

EIBC/IEI takes exception and argues that:

> Per Consumers' proposal, once it hits the statutory soft DG cap, a customer will not be able to enroll in the DG program, but can choose one of two contractual options

> to receive compensation for excess power the customer puts back on the grid: (1) the PURPA Standard Offer contract rate, via the Company's Rule C18, or (2) through an energy only contract at the wholesale market price of energy (MISO's LMP), described in proposed Rule C11.1, Self-Generation.  4 TR 580; Exhibit A-16, Tariff Sheet Nos. C-58.00 – C-58.10.  Consumers proposes that Rule C11.1 would be available to customers who meet the Federal Energy Regulatory Commission's ("FERC") criteria for a qualified facility ("QF"), but elect not to participate in the Company's Standard Offer under Rule C18.

EIBC/IEI's exceptions, p. 8.  EIBC/IEI asserts that the ALJ's deferral of the issue to a complaint proceeding or the next PURPA avoided cost proceeding is in error because Consumers is seeking approval of Rule C11.1 in the instant case.  EIBC/IEI states that the Commission should "either reject Rule C11.1 or order that the proposed rule must be modified to comply with PURPA and FERC Order 872," otherwise "the adoption of proposed Rule C11.1 would negatively affect small QFs, independent solar providers, and the Company's customers, in general . . . ."  EIBC/IEI's exceptions, pp. 9-12 (citing *Qualifying Facility Rates and Requirements Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, 172 FERC ¶ 61,041 (Issued July 16, 2020) (FERC Order 872)).

Similarly, JCEO excepts, also noting that customers who choose to install DG after the soft cap has been met have two options and that "customers electing to take service under tariff C11.1 would receive the market price of energy but would not receive *any* compensation for any of the other benefits that their DG systems provide to the Company—including capacity, avoided transmission cost, or avoided distribution costs."  JCEO's exceptions, p. 4 (emphasis in original). JCEO also argues that Consumers must demonstrate that this new rate is just, reasonable, and cost-based and contends that the company has failed to meet this burden.  *Id*., pp. 5-10.  JCEO relies upon MCL 460.11(1) to argue that DG customers "must be *charged and paid* rates that are based on the cost of service of the customer class and reflect the customer's 'fair and equitable use of the electric grid.'"  *Id*., p. 6 (emphasis in original).

In reply to EIBC/IEI, Consumers asserts that proposed Rule C11.1 is not a request for approval of a new self-generation provision; rather, it is a proposal to consolidate the existing self-generation provisions, contained in numerous rates, to one location. Consumers' replies to exceptions, p. 103. The company argues that EIBC/IEI "conflates PURPA requirements with what must be in the self-generation provision" because "[t]he self-generation provision is not a PURPA rate and does not require modification as a result of PURPA." *Id*., p. 104. Consumers states that the company has approved rates, in compliance with PURPA (Rule C18), and as a result, there is no need to modify the self-generation provision; doing so would improperly subvert the approved PURPA construct.

In addition, Consumers notes that "FERC Order 872 was issued after all direct and rebuttal testimony was filed in this matter and therefore, this proceeding lacks appropriate record evidence from which the Commission could fully consider the implications of FERC Order 872." *Id*., pp. 104-105 (citing FERC Order 872). The company contends that the Commission has already commenced a proceeding to consider the implementation of FERC Order 872, Case No. U-20905, and that any issues raised by EIBC/IEI should be considered in Case No. U-20905 or in the company's 2021 IRP where its PURPA construct will be evaluated.

Moreover, Consumers asserts the self-generation rate is a cost-based rate and that increasing the self-generation compensation "would unreasonably compensate DG customers with above-market rates to the detriment of the Company's [other] customers." Consumers' replies to exceptions, p. 105. The company also contends "that the contracting process could become burdensome for certain DG customers, the Company and the Commission once the statutory DG cap is filled" but that:

> at this time, the Company does not support an approach that would not require QFs to enter contracts with the Company because several issues need to be resolved first

> including: (i) the Company's retail billing system would need to be updated to handle the transactions on retail bills; (ii) the issue of early termination security associated with the term of the program participation and potential MISO penalties needs to be resolved; and (iii) the frequency and method by which the fixed or variable rates to be applied to the program are to be updated needs to be determined.

*Id*., pp. 106-107 (citing 6 Tr 1584). Consumers further notes that it proposes to resolve such issues through stakeholder sessions with the Staff and other interested parties. Therefore, the company requests that the Commission reject EIBC/IEI's exceptions and any request to make changes to Rule C18 in this proceeding.

Replying to JCEO, Consumers contends that JCEO's position should be rejected because it "is unreasonable and completely without merit." Consumers' replies to exceptions, p. 95. The company states that JCEO misinterprets the proposed Rule C11.1 as a new self-generation provision; however, the self-generation tariff was already approved and is presently contained in the company's ratebook. Consumers contends that it is "simply proposing to move the location of the provision" which it "has been using for many years" and is not "under any burden in this case to re-establish the reasonableness of the self-generation provision since it is not a new provision in the Company's Ratebook." *Id*., p. 96. The company also argues that MCL 460.11(1) is not applicable, as argued by JCEO, because that provision does not apply to compensation paid to customers. Consumers states that, even if MCL 460.11(1) applied to the self-generation tariff, the tariff would still be valid because it is cost-based. *Id*., pp. 97-98.

Further, the company avers that JCEO's request that the compensation under the self-generation tariff should be raised to match the net metering compensation should be rejected. Consumers contends that the self-generating provision does not fall under the statutory net metering and DG provisions, but is an option for certain generators to sell energy to the company. "JCEO's proposal would essentially render the Company's PURPA rates useless because QFs will simply go to the self-generation provision to acquire higher rates than what the Company is currently required to provide to QFs under PURPA." Consumers' replies to exceptions, p. 98.

The Staff also requests that the Commission reject JCEO's exceptions because requiring Rule C11.1 to compensate DG customers at the full retail rate after the soft cap has been met "is equivalent to lifting the cap and should be recognized by the Commission as such." Staff's replies to exceptions, p. 55.

The MEC Coalition replies, noting that it supports JCEO's exceptions "related to the reasonableness of Consumers' proposed tariff C11.1 for new DG customers." MEC Coalition's replies to exceptions, p. 135.

EIBC/IEI responds, noting its agreement with exceptions raised by JCEO, including the claim that Rule C11.1 is not just, reasonable, or based on cost-of-service principles as required by MCL 460.11. Therefore, EIBC/IEI contends that the ALJ erred and that "the Commission should either reject the tariff or direct the company to revise tariff C11.1 such that it compensates customers at the full retail rate until a comprehensive value of solar analysis is completed." EIBC/IEI's replies to exceptions, pp. 10-11.

In its replies, JCEO argues that Grand Rapids' argument against the 1% cap (discussed above) supports its "parallel argument: that the Company has not demonstrated that its proposed tariff C11.1 . . . is cost-based" and that the Commission should, therefore, set the rate under C11.1 at the full retail rate. JCEO's replies to exceptions, p. 10. JCEO contends that both Grand Rapids and JCEO "highlight the fundamental requirement, under Michigan law, that electric rates . . . be based on cost-of-service." *Id*., p. 11.

As previously stated, Rule C11.1 is not a new self-generation tariff proposed by the company. Rather, Rule C11.1 is merely a proposal by the company to consolidate its self-generation provisions, which are currently contained in numerous rates. *See*, 6 Tr 1620. Therefore, the Commission finds that these rates have already been approved and that the self-generation rates are not part of the company's approved PURPA rates.

The Commission also notes that a review of FERC Order 872 is ongoing in Case No. U-20905, and the Commission expects to provide guidance on the impacts and implications of FERC Order 872 in advance of the next round of PURPA avoided cost proceedings. Such guidance will have the benefit of addressing common issues across utilities, as opposed to articulating a standard on the broader impact of FERC Order 872 based on incomplete information in the instant case. On this basis, the Commission agrees with the ALJ's determination that "concerns about Consumers' self-generation tariff, in the event the company refuses to connect a customer and purchase energy 'as available,' should be addressed in a complaint, or in Consumers' next PURPA avoided cost proceeding." PFD, p. 420. Therefore, the Commission adopts the findings and recommendations of the ALJ on this issue.

EIBC/IEI also takes exception, arguing that the ALJ did not address its argument "as raised extensively in its filed testimony and briefings" that "there appear to be no Commission rules or regulations, or state statutes in Michigan, which specifically require investor-owned utilities to interconnect residential and small commercial solar systems less than 100 kW in size to the utility grid once the [DG] cap for that utility is reached." EIBC/IEI's exceptions, p. 4 (citing 8 Tr 4458-4459). EIBC/IEI further state that the ALJ provided a brief summary of its evidentiary support at page 404 of the PFD, but only concluded that the interconnection rules are in the process of being updated and that interested parties could participate in the ongoing workgroup. EIBC/IEI contends that this is insufficient and that the Commission must determine whether there is a "Commission or statutory requirement for consumers to interconnect a small solar customer outside of a net metering or DG program" and, if no such protections exist, the Commission "should determine whether federal law requires Consumers to interconnect a small solar customer." EIBC/IEI's exceptions, p. 6.

In reply, Consumers indicates that the ALJ properly deferred the consideration of this issue because, at the present time, Consumers is not refusing to interconnect facilities. The company notes that there is not a Michigan law that specifically requires it to interconnect solar generators. However, Consumers states that, "under the Michigan Administrative Rule R 460.620 of the current Electric Interconnection and Net Metering Standards and as federally mandated by PURPA in 23 CFR Subsection C, § 292.303," the company "will continue to permit the interconnection of solar generators in a safe and reliable manner once the cap is reached." Consumers' replies to exceptions, p. 101.

The Commission takes note of EIBC/IEI's concerns and comments but finds that the record does not include any disagreement about whether Consumers will continue to interconnect facilities. As Consumers states in its replies to exceptions, "participation in the DG Program or Net Metering Program is not a prerequisite to interconnection. The right to interconnect is, and will continue to be, independent of the applicant's desire or ability to participate in any particular program or contract." *Id*. The Commission therefore finds there is no active issue or controversy to be decided in this case.

Furthermore, the Commission notes that Consumers has stated that, "following review of the DG tariff approved in this proceeding, including the compensation for DG customers, the Company will consider agreeing to voluntarily raise its DG program limit from the 1% limit provided for in MCL 460.1173(3) to 2% of the average in-state peak load for the preceding five calendar years. This voluntary increase in the DG program limit is expected to be effective upon the effective date of the DG tariff." Consumers' replies to exceptions, pp. 102-103. Should Consumers ultimately agree to voluntarily lift DG participation in this way, it may provide additional time to address the many issues around interconnection and compensation for DG systems raised in this proceeding.

2. Contribution in Aid of Construction

The MEC Coalition proposed updated CIAC policies, which it contends predate unbundled ratemaking. 8 Tr 3669-3670. Consumers responded that it supported changes to CIAC policy, but due to the complexity of the issue, recommended that modifications be delayed to a future rate case or docket dedicated to the review and modification of CIAC policies. 6 Tr 1629.

The ALJ found that the CIAC policies are complex and should not be addressed in a piecemeal approach as presented by the MEC Coalition in this proceeding. Therefore, she recommended that "the Commission should initiate a workgroup or technical conference on CIAC policies and tariffs with the objective of presenting updated tariffs in Consumers' next rate case." PFD, p. 421.

Consumers takes exception because it "is concerned with any requirement that a new CIAC policy must be filed in its next rate case proceeding" and "disagrees with any definitive timeline for an ultimate CIAC proposal." Consumers' exceptions, p. 248. The company avers that, if an improved policy can be fully evaluated through a workgroup prior to the filing of its next rate case proceeding, Consumers will include such a proposal; however, the company states that if the workgroup needs additional time "the Commission should be supportive of such thoroughness." *Id*.

In reply, the MEC Coalition argues that the Commission should reject Consumers' proposal for CIAC reform to be an open-ended process. Citing its "comprehensive analysis and proposal" on the record, the MEC Coalition further states that the instant case "is the appropriate and lawful proceeding for the utility and any other interested party to propose policy modifications, and for other interested parties to consider, evaluate, and react to them through testimony, discovery, rebuttal testimony, cross examination, and briefing." MEC Coalition's replies to exceptions, p. 138. The MEC Coalition contends that "delaying this issue to the next rate case is already delaying the appropriate regulatory action on this important issue." *Id*. The MEC Coalition also argues that "[e]very year that the current CIAC policy remains in place, the residential class will continue to subsidize new industrial class customers." *Id*., p. 139. In addition, the MEC Coalition points out that the company could have initiated a workgroup on this issue last June when its testimony was filed or upon the issuance of the PFD in October 2020. Furthermore, the MEC Coalition contends that Consumers could have reviewed and responded to the analysis as part of this case through discovery, rebuttal, cross-examination, and briefing but did not. Therefore, the MEC Coalition avers that the company "has already demonstrated a dilatory approach to CIAC modification, which supports an order from the Commission requiring Consumers to present CIAC modification in its next rate case." *Id*., p. 139-140.

After reviewing the record, the Commission finds the ALJ's recommendation for a workgroup on CIAC policies and tariffs to be reasonable and prudent. As noted by the MEC Coalition, this issue may predate unbundled ratemaking, and developing a new approach should not be rushed in order to include changes in a case that may be filed as soon as two months from now. As such, the Commission directs the Staff to convene a work group in 2021 to consider updates to CIAC policies. As with the streetlighting technical conference discussed in Section VI.I. above, in convening the work group, the Staff shall provide notice to the parties in this docket; establish a framework for participation and a conference schedule; and, in collaboration with participants, a list of topics, issues, and objectives to be addressed and achieved. At the conclusion of the work group, the Staff shall file with the Commission a report not later than January 15, 2022, detailing its findings and recommendations regarding any recommended changes to the Commission's CIAC policies that can be considered in future rate cases. As such, the Commission does not adopt the findings and recommendations of the ALJ that updated tariffs should be included in the company's next rate case.

As noted above, the Commission's offices are currently closed and public meetings as well as workgroups are being conducted remotely due to the ongoing COVID-19 pandemic. Because of the uncertainty as to how long the pandemic will impact Commission operations, the Commission places interested parties on notice that this work group may be conducted remotely.

3. Rate Implementation Date

The Staff proposed that the effective date of the rates should be set seven calendar days from the date the order is issued in order to provide time for the company's billing system to be updated with the new rates and to help avoid errors. 8 Tr 4706. In the alternative, the Staff proposed that the Commission issue draft rates with its final decision and provide 21 days for the parties to comment and verify the calculations and tariff sheets. If no errors are identified in the comment period, the Staff stated that the rates and tariffs would take effect automatically, otherwise the rates and tariffs would be corrected and approved by the Commission in a subsequent order. *Id.*, pp. 4707.

Consumers responded to the Staff's proposals, arguing that it "is able to update its billing system for new prices to be effective the day after an order is issued" and that "[a] robust bill testing process has been implemented by the Company that allows timely, error-free updates to existing rate structures." 6 Tr 1630. The company contends that, depending on the date of the Commission's order, delaying the rate effective date by seven days may result in financial harm to the company because it "may unintentionally result in new base rates becoming effective after the start of the projected test year." *Id*. Therefore, Consumers proposed that the Commission should order that the new base rates become effective on the first day of the following test year, January 1, 2021, which it alleges is consistent with prior Commission orders. The company also opposed the Staff's alternative methodology, arguing that the potential 30 day delay "would unnecessarily delay the implementation of the rates beyond the period described in the statute or require that the initial final order be issued earlier than otherwise necessary" and "would effectively make what is intended to be a ten-month case into an eleven-month case." *Id*., p. 1631. Consumers stated that any errors can be corrected, as soon as possible, through the issuance of errata orders which have typically been issued within just a few short days and which has worked well in past cases. *Id*., p. 1632.

In exceptions, the Staff argues that the ALJ did not make a recommendation regarding the rate implementation date. The Staff reiterates its proposal and alternative methodology, as set forth above. The Staff argues that it "has been consistently proposing new rate implementation dates in its recent cases to try to improve upon past procedures." Staff's exceptions, p. 13. The Staff agrees with Consumers that the current procedure is for the Commission to issue an errata order setting forth new rates if any errors had been made in calculating the final rates but that "customers may still be subject to inaccurate rates based upon timing" and the Staff's proposals "would avoid erroneous rates being charged to customers." *Id*., pp. 13-14. Furthermore, the Staff counters that its alternative methodology would not violate MCL 460.6a(5) because the Commission's final decision would be issued within the 10-month period provided under the statute.

Quoting the Court of Appeals ruling in *In re Indiana Michigan Power Co*, unpublished per curiam opinion of the Court of Appeals, issued August 13, 2019 (Docket No. 343767), the Staff contends that the company's arguments were addressed and rejected in the ruling which affirmed the Commission's decision to delay the implementation of rates by two weeks. *See*, Staff's exceptions, pp. 14-15. The Staff further argues that Consumers did not quantify the purported financial impact that a delayed implementation date would cause. The Staff states that the Court of Appeals "affirmed that merely because [the utility] could have collected a higher rate for those two weeks after the Commission's initial order that the delay in implementation would not deny a 'just and reasonable rate of return on its investment.'" *Id*., p. 15 (quoting *ABATE v Pub Serv Comm*, 208 Mich App 248, 269 (1994). The Staff again argues that finding errors prior to the implementation of new rates is in the best interest of all parties and customers, and that providing additional time for parties to review "simply creates a more thorough review to be made . . . ." Staff's exceptions, p. 16.

In reply, Consumers again opposes the Staff's proposals. The company argues that the Staff did not provide evidence of prior inaccuracies that were not able to be corrected prior to the implementation of rates or that such inaccuracies "are a regular and recurring theme that would warrant the need to delay the effectiveness of the Company's rates in this proceeding or any future electric rate case proceedings." Consumers' replies to exceptions, pp. 117-118. Consumers replies that the Staff has not demonstrated why the past Commission practice of issuing an errata order "should not be the appropriate mechanism to correct inaccurate rates or tariffs previously approved by the Commission in the unlikely event that such inaccuracies occur." *Id*., p. 118. The company further alleges that "despite Staff's reference to the 2019 Michigan Court of Appeals case, there is no need to require a delay to the effectiveness of rates" and that the Commission should dismiss the Staff's proposals until it "can present sufficient evidence to show a regular and recurring trend of rate and tariff inaccuracies that occur within the Company's electric rate case proceedings . . . ." *Id*., pp. 119-120. Consumers avers that, in this case, the Commission should find that new base rates should become effective for service rendered on January 1, 2021, which is consistent with its contract with HSC, as discussed previously.

The Commission has considered each of the Staff's proposals for rate effective dates and finds that, given the timing of the order in this case, there is no conflict between having the rates take effect on January 1, 2021, and the Staff's proposal to provide for a seven day window to allow for any errors to be corrected prior to rate implementation. Therefore, the Commission finds that the rates shall be effective January 1, 2021.

THEREFORE, IT IS ORDERED that:

A. Based on this order's findings adopting a January 1, 2021, through December 31, 2021, test year, a jurisdictional rate base of $11,660,441,000, an authorized rate of return on common equity of 9.90%, and an authorized overall rate of return of 5.67%, Consumers Energy Company is authorized to implement rates that increase its annual electric revenues by $90,220,000, on a jurisdictional basis, over the rates approved in the January 9, 2019 order in Case No. U-20134.

B. Consumers Energy Company is authorized to implement rates consistent with the revenue deficiency approved by this order on a service-rendered basis for service provided on and after January 1, 2021, as reflected in Attachment A (a summary of revenue by rate class), Attachment B (tariff sheets), and Attachment C (calculation of the capacity charge as updated by this order) to this order. Within 30 days of the date of this order, Consumers Energy Company shall file tariff sheets substantially similar to Attachment B. When filing the tariffs consistent with those ordered, Consumers Energy Company shall also update the Contribution In Aid of Construction Allowance Schedule amounts on Tariff Sheet C-4.00, Section C1.4, to be consistent with the rates approved in this order. Consumers Energy Company shall implement a state reliability mechanism capacity charge of $136,857 per megawatt-year, or $374.95 per megawatt-day, for customers taking capacity service, as shown on Attachment C to this order. Attachment B contains the associated capacity rates.

C. In its next general rate case, Consumers Energy Company shall include in its information technology plan detail regarding the Customer Relationship Management and Advanced Analytics Hub programs including, but not limited to, a benefit/cost analysis for the programs; the information technology and software needed to optimize customer service and enrollment in programs such as energy waste reduction, demand response, and renewable energy; and quantification of the expected growth in effected programs as a result of the projects.

D. In future rate case filings, and consistent with this order, Consumers Energy Company shall, in describing projected capital expenditures, provide the following information: (1) future load forecasts shall be based on advanced metering infrastructure data and other data such as a hosting capacity analysis or interconnection process information; (2) load forecasts shall be aligned between the company's most recent five-year distribution investment and maintenance plan and the currently-approved integrated resource plan; and (3) rate base distribution capital spending shall, where possible, be aligned with the most recent five-year distribution investment and maintenance plan, and, where alignment is not possible, an explanation shall be included.

E. In its next integrated resource plan application, Consumers Energy Company shall include the cost of the Centralized Demand Response Assessment project and the costs assigned to the demand response resources the company supports, as described in this order.

F. Consumers Energy Company shall include demand response pilot program updates, consistent with this order, in the Demand Response Annual Report.

G. The Commission Staff shall convene a work group in 2021 to consider updates to policies addressing contributions in aid of construction. The Commission Staff shall provide notice to the parties in this docket; establish a conference schedule and a framework for participation; and, in collaboration with conference participants, a list of topics, issues, and objectives to be addressed and achieved. At the conclusion of the work group, the Commission Staff shall file a report in this docket, no later than January 15, 2022, detailing its findings and recommendations regarding any recommended changes to the Commission's contributions in aid of construction policies.

H. The Commission Staff shall convene a technical collaborative in 2021, with the participation of Consumers Energy Company, to evaluate improvements to Consumers Energy Company's municipal lighting program and to address issues including, but not limited to, light-emitting diode conversion and updates to municipal streetlighting technology and service in the last decade. The Commission Staff shall provide notice to the parties in this docket; establish a schedule and a framework for participation; and, in collaboration with participants, a list of topics, issues, and objectives to be addressed and achieved. At the conclusion of the work group, the Commission Staff shall file a report in this docket, no later than December 15, 2021, detailing its findings and recommendations.

I. The Commission Staff shall convene a low-income workgroup in 2021 with the participation of Consumers Energy Company. As described in this order, in this collaborative Consumers Energy Company shall provide a proposal for a percentage-of-income pilot program for its electric service customers.

J. Consumers Energy Company shall include a performance-based regulation proposal consistent with the direction in this order in its upcoming distribution investment and maintenance plan to be filed no later than September 30, 2021, and shall share a draft of the plan with stakeholders and the Commission Staff by August 1, 2021.

K. In the first quarter of 2021, the Commission Staff shall initiate a Value of Solar work group, as described in this order.

L. In future rate case filings, Consumers Energy Company shall use appropriate line loss factors, as described in this order, for retail open access customers.

M. In future rate case filings, Consumers Energy Company shall provide inflation projections supported by appropriate documentation, as described in this order.

N. In future rate case filings, Consumers Energy Company shall provide corporate services projections supported by appropriate documentation, as described in this order.

O. Consumers Energy Company shall file an annual report in this docket no later than December 15, 2021, and meet periodically with the Commission Staff throughout the year, to evaluate the company's progress toward its line-clearing goals, to refine program metrics, and to discuss future strategies.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order under MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of Attorney General - Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Daniel C. Scripps, Chair

Sally A. Talberg, Commissioner

Tremaine L. Phillips, Commissioner

By its action of December 17, 2020.

Lisa Felice, Executive Secretary

# ATTACHMENT A

**Schedule F2**

**MICHIGAN PUBLIC SERVICE COMMISSION** Case No.: U-20697
Consumers Energy Company Attachment A
Summary of Present and Proposed Pro Forma Revenues by Rate Schedule Page 1 of 3
Total Revenues

| | ( a ) | ( b ) | ( c ) | ( d ) | ( e ) | ( f ) | ( g ) |
|---|---|---|---|---|---|---|---|
| Line | | | | Revenue | | Net Increase / (Decrease) | |
| No. | Description | Customers | Sales | Present | Proposed | Revenue | Percent |
| | | Mthly | MWh | $000 | $000 | $000 | % |
| | **BUNDLED SERVICE** | | | | | | |
| | Residential Class | | | | | | |
| 1 | Summer On-peak RSP | 1,601,135 | 12,247,759 | $ 1,972,508 | $ 2,135,394 | $ 162,886 | 8.3 |
| 2 | Smart Hours RSH | 2,666 | 60,975 | 9,320 | 10,194 | 874 | 9.4 |
| 3 | Night Time Savers RPM | 676 | 8,045 | 1,233 | 1,316 | 83 | 6.7 |
| 4 | Non-Transmitting Meters RSM | 16,221 | 130,889 | 21,438 | 23,453 | 2,015 | 9.4 |
| 5 | Total Residential Class | 1,620,698 | 12,447,668 | $ 2,004,498 | $ 2,170,357 | $ 165,858 | 8.3 |
| | Secondary Class | | | | | | |
| 6 | Energy-only GS | 195,747 | 3,826,453 | $ 593,299 | $ 597,254 | $ 3,955 | 0.7 |
| 7 | Time-of-Use GSTU | 72 | 3,265 | 484 | 487 | 3 | 0.6 |
| 8 | Demand GSD | 19,907 | 3,256,731 | 433,955 | 424,070 | (9,885) | (2.3) |
| 9 | Total Secondary | 215,726 | 7,086,449 | $ 1,027,738 | $ 1,021,811 | $ (5,927) | (0.6) |
| | Primary Class | | | | | | |
| 10 | Energy-only GP | 1,598 | 952,493 | $ 120,078 | $ 101,233 | $ (18,844) | (15.7) |
| 11 | Demand GPD | 1,059 | 4,950,918 | 463,196 | 412,266 | (50,930) | (11.0) |
| 12 | Time-of-Use GPTU | 1,032 | 4,365,549 | 419,677 | 415,862 | (3,815) | (0.9) |
| 13 | Energy Intensive EIP | 19 | 358,537 | 24,200 | 23,763 | (436) | (1.8) |
| 14 | Total Primary | 3,708 | 10,627,497 | $ 1,027,150 | $ 953,125 | $ (74,026) | (7.2) |
| | Lighting & Unmetered Class | | | | | | |
| 15 | Metered Lighting GML | 343 | 13,509 | $ 1,610 | $ 1,536 | $ (75) | (4.6) |
| 16 | Unmetered Lighting GUL | 3,735 | 61,241 | 18,248 | 19,975 | 1,727 | 9.5 |
| 17 | Unmetered GU-XL / LED | 797 | 20,629 | 8,019 | 7,724 | (295) | (3.7) |
| 18 | Unmetered GU | 479 | 95,012 | 9,295 | 9,478 | 183 | 2.0 |
| 19 | Total Lighting & Unmetered | 5,354 | 190,391 | $ 37,173 | $ 38,713 | $ 1,540 | 4.1 |
| | Self-generation Class | | | | | | |
| 20 | Small Self-generation GSG-1 | - | - | $ - | $ - | $ - | NA |
| 21 | Large Self-generation GSG-2 | 12 | 63,483 | 5,609 | 5,431 | (178) | (3.2) |
| 22 | Total Self-generation | 12 | 63,483 | $ 5,609 | $ 5,431 | $ (178) | (3.2) |
| 23 | Total Bundled Service | 1,845,498 | 30,415,489 | $ 4,102,169 | $ 4,189,437 | $ 87,268 | 2.1 |
| | **ROA SERVICE** | | | | | | |
| | Secondary Class | | | | | | |
| 24 | Energy-only GS | 110 | 24,480 | $ 1,055 | $ 1,185 | $ 130 | 12.3 |
| 25 | Demand GSD | 477 | 180,859 | 6,116 | 6,583 | 467 | 7.6 |
| 26 | Total Secondary | 587 | 205,339 | $ 7,171 | $ 7,767 | $ 596 | 8.3 |
| | Primary Class | | | | | | |
| 27 | Energy-only GP | 54 | 74,331 | $ 1,028 | $ 1,172 | $ 144 | 14.0 |
| 28 | Demand GPD | 354 | 3,417,757 | 17,997 | 20,334 | 2,336 | 13.0 |
| 29 | Total Primary | 408 | 3,492,088 | $ 19,025 | $ 21,506 | $ 2,481 | 13.0 |
| 30 | Total ROA Service | 995 | 3,697,427 | $ 26,196 | $ 29,273 | $ 3,077 | 11.7 |
| 31 | Total Jurisdictional Service | 1,846,493 | 34,112,916 | $ 4,128,365 | $ 4,218,710 | $ 90,345 | 2.2 |
| 32 | Less: PSCR Factor Revenues | | | 134,423 | 134,423 | - | |
| 33 | Less: GSG-2 and GI-2 PSCR Revenues | | | 5,960 | 6,096 | 136 | |
| 34 | Total Jurisdictional Base Revenues | | | $ 3,987,982 | $ 4,078,191 | $ 90,209 | |
| 35 | Rounding | | | | (68) | 11 | |
| 36 | Total Jurisdictional Base Revenues | | | | $ 4,078,123 | $ 90,220 | |

**Schedule F2**

**MICHIGAN PUBLIC SERVICE COMMISSION** Case No.: U-20697

Consumers Energy Company Attachment A

Summary of Present and Proposed Pro Forma Revenues by Rate Schedule 

Production & Transmission Revenues

| | (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|
| | | | Revenue | | Net Increase / (Decrease) | |
| Line No. | Description | Sales | Present | Proposed | Revenue | Percent |
| | | MWh | $000 | $000 | $000 | % |
| | **BUNDLED SERVICE** | | | | | |
| | Residential Class | | | | | |
| 1 | Summer On-peak RSP | 12,247,759 | $ 1,270,946 | $ 1,319,153 | $ 48,207 | 3.8 |
| 2 | Smart Hours RSH | 60,975 | 6,241 | 6,566 | 325 | 5.2 |
| 3 | Night Time Savers RPM | 8,045 | 793 | 802 | 8 | 1.1 |
| 4 | Non-Transmitting Meters RNT | 130,889 | 13,473 | 14,243 | 769 | 5.7 |
| 5 | Total Residential Class | 12,447,668 | $ 1,291,453 | $ 1,340,764 | $ 49,310 | 3.8 |
| | Secondary Class | | | | | |
| 6 | Energy-only GS | 3,826,453 | $ 383,868 | $ 367,493 | $ (16,375) | (4.3) |
| 7 | Time-of-Use GSTU | 3,265 | 328 | 314 | (14) | (4.4) |
| 8 | Demand GSD | 3,256,731 | 319,627 | 300,986 | (18,641) | (5.8) |
| 9 | Total Secondary | 7,086,449 | $ 703,823 | $ 668,792 | $ (35,030) | (5.0) |
| | Primary Class | | | | | |
| 10 | Energy-only GP | 952,493 | $ 105,669 | $ 84,995 | $ (20,673) | (19.6) |
| 11 | Demand GPD | 4,950,918 | 430,127 | 375,437 | (54,691) | (12.7) |
| 12 | Time-of-Use GPTU | 4,365,549 | 378,499 | 368,710 | (9,789) | (2.6) |
| 13 | Energy Intensive EIP | 358,537 | 22,488 | 21,978 | (510) | (2.3) |
| 14 | Total Primary | 10,627,497 | $ 936,783 | $ 851,120 | $ (85,663) | (9.1) |
| | Lighting & Unmetered Class | | | | | |
| 15 | Metered Lighting GML | 13,509 | $ 740 | $ 726 | $ (14) | (1.9) |
| 16 | Unmetered Lighting GUL | 61,241 | 3,369 | 3,249 | (120) | (3.6) |
| 17 | Unmetered GU-XL / LED | 20,629 | 1,088 | 1,083 | (4) | (0.4) |
| 18 | Unmetered GU | 95,012 | 7,646 | 7,471 | (175) | (2.3) |
| 19 | Total Lighting & Unmetered | 190,391 | $ 12,842 | $ 12,529 | $ (313) | (2.4) |
| | Self-generation Class | | | | | |
| 20 | Small Self-generation GSG-1 | - | $ - | $ - | $ - | NA |
| 21 | Large Self-generation GSG-2 | 63,483 | 4,015 | 4,015 | - | - |
| 22 | Total Self-generation | 63,483 | $ 4,015 | $ 4,015 | $ - | - |
| 23 | Total Bundled Service | 30,415,489 | $ 2,948,916 | $ 2,877,220 | $ (71,696) | (2.4) |
| | **ROA SERVICE** | | | | | |
| | Secondary Class | | | | | |
| 24 | Energy-only GS | - | $ - | $ - | $ - | NA |
| 25 | Demand GSD | - | - | - | - | NA |
| 26 | Total Secondary | - | $ - | $ - | $ - | NA |
| | Primary Class | | | | | |
| 27 | Energy-only GP | - | $ - | $ - | $ - | NA |
| 28 | Demand GPD | - | - | - | - | NA |
| 29 | Total Primary | - | $ - | $ - | $ - | NA |
| 30 | Total ROA Service | - | $ - | $ - | $ - | NA |
| 31 | Total Jurisdictional Service | 30,415,489 | $ 2,948,916 | $ 2,877,220 | $ (71,696) | (2.4) |
| 32 | Less: PSCR Factor Revenues | | 134,423 | 134,423 | - | |
| 33 | Less: GSG-2 and GI-2 PSCR Revenues | | 5,960 | 6,096 | 136 | |
| 34 | Total Jurisdictional Base Revenues | | $ 2,808,533 | $ 2,736,701 | $ (71,832) | |
| 35 | Rounding | | | (10) | | |
| 36 | Total Jurisdictional Base Revenues | | | $ 2,736,692 | | |

**Schedule F2**

**MICHIGAN PUBLIC SERVICE COMMISSION** — Case No.: U-20697

Consumers Energy Company — Attachment A

Summary of Present and Proposed Pro Forma Revenues by Rate Schedule — 

Delivery Revenues

| | (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|
| Line | | | Revenue | | Net Increase / (Decrease) | |
| No. | Description | Sales | Present | Proposed | Revenue | Percent |
| | | MWh | $000 | $000 | $000 | % |
| | **BUNDLED SERVICE** | | | | | |
| | Residential Class | | | | | |
| 1 | Summer On-peak RSP | 12,247,759 | $ 701,562 | $ 816,241 | $ 114,679 | 16.3 |
| 2 | Smart Hours RSH | 60,975 | 3,079 | 3,628 | 549 | 17.8 |
| 3 | Night Time Savers RPM | 8,045 | 439 | 514 | 75 | 17.0 |
| 4 | Non-Transmitting Meters RNT | 130,889 | 7,965 | 9,211 | 1,245 | 15.6 |
| 5 | Total Residential Class | 12,447,668 | $ 713,045 | $ 829,593 | $ 116,548 | 16.3 |
| | Secondary Class | | | | | |
| 6 | Energy-only GS | 3,826,453 | $ 209,431 | $ 229,762 | $ 20,331 | 9.7 |
| 7 | Time-of-Use GSTU | 3,265 | 156 | 173 | 17 | 11.1 |
| 8 | Demand GSD | 3,256,731 | 114,329 | 123,084 | 8,756 | 7.7 |
| 9 | Total Secondary | 7,086,449 | $ 323,915 | $ 353,019 | $ 29,104 | 9.0 |
| | Primary Class | | | | | |
| 10 | Energy-only GP | 952,493 | $ 14,409 | $ 16,238 | $ 1,829 | 12.7 |
| 11 | Demand GPD | 4,950,918 | 33,069 | 36,829 | 3,761 | 11.4 |
| 12 | Time-of-Use GPTU | 4,365,549 | 41,177 | 47,152 | 5,974 | 14.5 |
| 13 | Energy Intensive EIP | 358,537 | 1,712 | 1,786 | 74 | 4.3 |
| 14 | Total Primary | 10,627,497 | $ 90,367 | $ 102,005 | $ 11,638 | 12.9 |
| | Lighting & Unmetered Class | | | | | |
| 15 | Metered Lighting GML | 13,509 | $ 871 | $ 810 | $ (61) | (7.0) |
| 16 | Unmetered Lighting GUL | 61,241 | 14,880 | 16,727 | 1,847 | 12.4 |
| 17 | Unmetered GU-XL / LED | 20,629 | 6,931 | 6,640 | (291) | (4.2) |
| 18 | Unmetered GU | 95,012 | 1,649 | 2,007 | 358 | 21.7 |
| 19 | Total Lighting & Unmetered | 190,391 | $ 24,331 | $ 26,184 | $ 1,853 | 7.6 |
| | Self-generation Class | | | | | |
| 20 | Small Self-generation GSG-1 | - | $ - | $ - | $ - | NA |
| 21 | Large Self-generation GSG-2 | 63,483 | 1,594 | 1,416 | (178) | (11.2) |
| 22 | Total Self-generation | 63,483 | $ 1,594 | $ 1,416 | $ (178) | (11.2) |
| 23 | Total Bundled Service | 30,415,489 | $ 1,153,252 | $ 1,312,216 | $ 158,964 | 13.8 |
| | **ROA SERVICE** | | | | | |
| | Secondary Class | | | | | |
| 24 | Energy-only GS | 24,480 | $ 1,055 | $ 1,185 | $ 130 | 12.3 |
| 25 | Demand GSD | 180,859 | 6,116 | 6,583 | 467 | 7.6 |
| 26 | Total Secondary | 205,339 | $ 7,171 | $ 7,767 | $ 596 | 8.3 |
| | Primary Class | | | | | |
| 27 | Energy-only GP | 74,331 | $ 1,028 | $ 1,172 | $ 144 | 14.0 |
| 28 | Demand GPD | 3,417,757 | 17,997 | 20,334 | 2,336 | 13.0 |
| 29 | Total Primary | 3,492,088 | $ 19,025 | $ 21,506 | $ 2,481 | 13.0 |
| 30 | Total ROA Service | 3,697,427 | $ 26,196 | $ 29,273 | $ 3,077 | 11.7 |
| 31 | Total Jurisdictional Service | 34,112,916 | $ 1,179,449 | $ 1,341,490 | $ 162,041 | 13.7 |
| 32 | Rounding | | | (58) | | |
| 33 | Total Jurisdictional Base Revenues | | | $ 1,341,432 | | |

# INDEX

**(Continued From Sheet No. A-3.00)**

## SECTION C
## COMPANY RULES AND REGULATIONS (Contd)

**Part I - Applicable to All Customers (Contd)** **Sheet No.**



**Part II - Renewable Energy and Energy Efficiency, Applicable to All Customers**



**Part III - Applicable to Non-Residential Customers**



**Part IV - Applicable to All Customers**



## SECTION D
## RATE SCHEDULES



**(Continued on Sheet No. A-5.00)**

# INDEX

**(Continued From Sheet No. A-4.00)**

## SECTION D
## RATE SCHEDULES (Contd)



**(Continued on Sheet No. A-6.00)**

# INDEX

**(Continued From Sheet No. A-5.00)**

## SECTION E
## RETAIL OPEN ACCESS (ROA) SERVICE STANDARDS



## SECTION F
## STANDARD CUSTOMER FORMS INDEX



**(Continued on Sheet No. A-7.00)**

**(Continued From Sheet No. C-14.00)**

**C4. APPLICATION OF RATES (Contd)**

**C4.3 Application of Residential Usage and Non-Residential Usage (Contd)**

D. Rate Application for Seasonal Condominium Campgrounds (Contd)

(6) The customer must notify individuals and co-owners utilizing the customer's property that requests and concerns regarding electric service will be addressed between the single legal entity and ownership and primary operating authority, not with individuals.

(7) The customer shall be responsible for ensuring that the electrical facilities are adequate to meet the needs of the units placed within the Seasonal Condominium Campground in their entirety and shall pay the Company for any charges incurred for modifications necessary to accommodate load according to other portions of this Electric Rate Book.

**C4.4 Resale**

This provision is closed to resale for general unmetered service, unmetered or metered lighting service and new or expanded service for resale for residential use.

No customer shall resell electric service to others except when the customer is served under a Company rate expressly made available for resale purposes, and then only as permitted under such rate and under this rule.

Where, in the Company's opinion, the temporary or transient nature of the proposed ultimate use, physical limitation upon extensions, or other circumstances, make it impractical for the Company to extend or render service directly to the ultimate user, the Company may allow a customer to resell electric service to others.

For the purposes of this tariff, the provision of electric vehicle charging service for which there is no direct per kWh charge shall not be considered resale of service.

A resale customer is required to take service under the resale provision of one of the following rates for which they qualify: General Service Secondary Rate GS, General Service Secondary Time-of-Use Rate GSTU, General Service Secondary Demand Rate GSD, General Service Primary Rate GP, Large General Service Primary Demand Rate GPD, or General Service Primary Time-of-Use Rate GPTU. Resale Service is provided pursuant to a service contract providing for such resale privilege. Service to each ultimate user shall be separately metered.

A. If the resale customer elects to take service under a Company Full Service resale rate, the ultimate user shall be served and charged for such service under standard Rate *RSM* for residential use or under the appropriate standard General Service Rate applicable in the Company's Electric Rate Book available for similar service under like conditions. Reselling customers are not required to offer or administer any additional service provisions or nonstandard rates contained in the Electric Rate Book, such as the Income Assistance Service Provision or the Educational Institution Service Provision.

B. If the resale customer elects to take service under a Company Retail Open Access Service rate, the ultimate user shall be served and charged for such service under Rate ROA-R for residential use or under Rate ROA-S or ROA-P applicable in the Company's Electric Rate Book available for similar service under like conditions.

C. If the ultimate user is a campground lot or boat harbor slip, the resale customer has the option to charge a maximum of the following all inclusive rate per kWh in place of billing the ultimate customer on the appropriate standard Company tariff rate:

| | |
|---|---|
| $*0.146212* | per kWh for all kWh during the months of June-September |
| $*0.145170* | per kWh for all kWh during the months of October-May |

The Company shall be under no obligation to furnish or maintain meters or other facilities for the resale of service by the reselling customer to the ultimate user.

The service contract shall provide that the reselling customer's billings to the ultimate user shall be audited each year by February's month end, for the previous calendar year. The audit shall be conducted either by the Company, if the Company elects to conduct such audit, or by an independent auditing firm approved by the Company. The reselling customer shall be assessed a reasonable fee for an audit conducted by the Company. If the audit is conducted by an independent auditing firm, the customer shall submit a copy of the results of such audit to the Company in a form approved by the Company.

**(Continued on Sheet No. C-16.00)**

**(Continued From Sheet No. C-18.00)**

**C4. APPLICATION OF RATES (Contd)**

**C4.5 Mobile Home Park - Individually Served (Contd)**

Notwithstanding other provisions of this rule, an overhead distribution system shall be incorporated into the Company's electric distribution system originally as an overhead distribution system. Any subsequent conversion to underground distribution facilities shall be in accordance with the provisions of this rule. The mobile home park owner shall be responsible to provide a recordable easement granting rights-of-way suitable for installation and maintenance of the electric facilities; to provide, own, install and maintain suitable meter supports; to remove any unused existing electrical equipment not transferred to the utility; to make any necessary wiring changes to separate the electrical responsibilities of the park owner from those of the tenant; and to move mobile homes or other equipment as required to provide access to easements to facilitate maintenance or required upgrading of the existing system.

F. Extension Policy

Service to mobile home parks shall be subject to the provisions of Rule C6., Distribution Systems, Line Extensions and Service Connections.

G. Any charges, contributions or deposits may be required In Advance of commencement of construction.

**C5. CUSTOMER RESPONSIBILITIES**

**C5.1 Access to Customer's Premises**

The Company's authorized agents shall have access to the customer's premises at all reasonable hours, to install, inspect, read, repair or remove its meters; to install, operate, maintain or remove other Company property, and to inspect and determine the connected electrical load on the customer's premises. Neglect or refusal on the part of the customer to provide reasonable access shall be sufficient cause for shutoff of service by the Company, and assurance of access may be required before service is restored.

**C5.2 Bills and Payments**

A. Billing Frequency

Bills for electric service shall be rendered on approximately a monthly basis, and shall be due and payable on or before the due date shown on each bill.

B. Meter Reads and Estimated Bills

The Company shall schedule meters to be read on approximately a monthly basis and will attempt to read meters in accordance with such schedule.

When the Company is unable to obtain an actual meter reading, the bill shall be estimated on the basis of past service records, adjusted, as may be appropriate. Where past service records are not available or suitable for use, such billing shall be based upon whatever other service data are available. Each such account shall be adjusted as necessary each time an actual meter reading is obtained.

(1) Interval Data Estimation

*The Company requests usage data (including index and interval data) from smart meters daily. The usage data is stored in the meter data management system. The billing system requests the ending index read and time of use interval billing determinants (i.e., consumption of usage in each tier) for the billing cycle.*

*The billing system performs an industry standard sum check calculation comparing the sum of the interval billing determinant tiers to the difference of the starting and ending index.*

*When index data is missing, the billing system estimates the missing index read.*

*When interval data is missing, the delta is placed in the lower-tiered rate.*

*In the case where there is no missing data and the sum of the interval tiers exceeds difference of the index reads, the bill will be adjusted by a billing agent such that the excess interval tiered usage is removed from the higher priced tier.*

**(Continued on Sheet No. C-20.00)**

**(Continued From Sheet No. C-25.00)**

## C5. CUSTOMER RESPONSIBILITIES (Contd)

### C5.6 Customer-Selected Due Date Program

Notwithstanding other provisions in this tariff book, the Company, at its discretion, may provide its electric service customers and combination electric and gas service customers the option to select the day of the month on which their bill is due, regardless of the meter read date. Participating customers must have an electric AMI transmitting technology meter.

Participation in the Customer-Selected Due Date Program is available to customers, as determined by the Company, when technically feasible based on the customer's selected rate and billing options. Customers not eligible to participate include, but not limited to, customers billed on a calendar-month basis, customers participating in Retail Open Access and customers participating in the Net Metering Program.

The Customer-Selected Due Date Program is only available for the following rate categories: *Residential Summer On-Peak Basic (RSP), Residential Smart Hours (RSH), Residential Nighttime Savers (RPM),* General Service Secondary (GS), General Service Secondary Demand (GSD), General Service Primary (GP) and General Service Metered Lighting (GML).

## C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS

### C6.1 Overhead Extension Policy

Applications for electric service which require the construction of an overhead distribution system shall be granted under the following conditions:

A. Residential Customers

The Company shall construct single-phase distribution line extensions at its own cost a distance of 600 feet, for each residential dwelling.

The length of the distribution line extension shall be measured from the nearest point of connection to the Company's facilities from which the extension can be made to the point from which the service line to the customer shall be run.

Distribution line extensions in excess of the above 600 feet shall require a deposit for the estimated cost of such excess footage. The required deposit for such excess footage shall be $3.50 per lineal foot less 25%.

**(Continued on Sheet No. C-27.00)**

**(Continued From Sheet No. C-27.00)**

**C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)**

**C6.1 Overhead Extension Policy (Contd)**

C. General (Contd)

(6) The Company reserves the right to make special contractual arrangements as to the provision of necessary Service Facilities, duration of contract, amount of deposit and refunds thereon, minimum bills or other service conditions with respect to the customers or prospective customers whose load requirements exceed the capacity of the available distribution system in the area, or whose load characteristics or special service needs require unusual investments by the Company in Service Facilities or where there is not sufficient assurance of the permanence of the use of the service. The Company shall construct overhead electric distribution facilities and extensions only in the event it is able to obtain or use the necessary materials, equipment and supplies. The Company, subject only to review by the Commission, reserves the right, in its discretion, to allocate the use of such materials, equipment and supplies it may have on hand from time to time among the various classes of customers and prospective customers and among various customers and prospective customers of the same class.

(7) Contributions in Aid of Construction otherwise required by the Company may be suspended for publicly available AC Level 2 or DC Fast Charge sites participating in the PowerMIDrive pilot. Suspension is at the Company's sole discretion, for a term of three years from the date of Commission approval of the PowerMIDrive pilot.

(8) All service rendered shall be subject to the Company's Standard Contract forms and to its Electric Rate Book.

(9) Any charges, deposits or contributions may be required In Advance of commencement of construction.

**C6.2 Underground Policy**

A. General

This rule sets forth the conditions under which the Company shall install direct burial underground electric distribution systems and underground service connections for residential and General Service customers. For the purpose of this rule, such underground distribution facilities are defined as those facilities operated at 15,000 Volts or less phase to ground wye connected or 20,000 Volts or less phase to phase delta connected.

The general policy of the Company is that real estate developers, property owners or other applicants for underground service shall make a contribution in aid of construction to the Company in an amount equal to the estimated difference in cost between underground and equivalent overhead facilities. Methods for determining this cost differential for specific classifications of service are provided herein. In cases, where the nature of service or the construction conditions are such that these conditions are not applicable, the general policy stated above shall apply.

*In cases where the Company does not require underground electric distribution systems and/or underground service connections, but is required to underground such facilities by state or local law or regulation, the Company may adjust the contribution in aid of construction to account for such requirement.*

It shall be mandatory that all original electric distribution systems installed in new residential subdivisions and in existing residential subdivisions in which overhead electric distribution facilities have not already been constructed be placed underground, except that a lot within a subdivision facing a previously existing street or county road and having an existing overhead distribution line on its side of the street or county road shall be served with an underground service from these facilities and shall be considered a part of the underground service area. It shall also be mandatory that all original service connections installed to serve one-family or two-family dwellings from an underground distribution system be placed underground.

Except as otherwise provided in the following paragraph, it shall be mandatory that all new General Service distribution systems and service connections installed in the vicinity of or on the customer's premises to be served, and constructed solely to serve the customer or a group of adjacent customers, be placed underground.

**(Continued on Sheet No. C-29.00)**

**Consumers Energy Company**

**(Continued From Sheet No. C-35.00)**

**C8. POWER SUPPLY COST RECOVERY (PSCR) CLAUSE (Contd)**

A. Applicability of Clause (Contd)

"Power Supply Costs" means those elements of the costs of fuel and purchased and net interchanged power as determined by the Commission to be included in the calculation of the Power Supply Cost Recovery Factor. The Commission determined in its Order in Case No. U-10335 dated May 10, 1994 that the fossil plant emissions permit fees over or under the amount included in base rates charged the Company are an element of fuel costs for the purpose of the clause.

B. Billing

(1) The Power Supply Cost Recovery Factor shall consist of an adjustment factor of *1.08378* applied to projected average booked cost of fuel burned for electric generation and purchased and net interchange power incurred above or below a cost base of $0.05570 per kWh (excluding line losses). Average booked costs of fuel burned and purchased and net interchange power shall be equal to the booked costs in that period divided by that period's net system kWh requirements. The average booked costs so determined shall be truncated to the full $0.00001 cost per Kilowatt-hour. Net system kWh requirements shall be the sum of the net kWh generation and net kWh purchased and interchange power.

(2) Each month the Company shall include in its rates a Power Supply Cost Recovery Factor up to the maximum authorized by the Commission as shown on Sheet No. D-6.00.

Should the Company apply lesser factors than those shown on Sheet No. D-6.00, or if the factors are later revised pursuant to Commission Orders or Michigan Compiled Laws, Annotated, 460.6 et seq., the Company shall notify the Commission if necessary and file a revised Sheet No. D-6.00.

C. General Conditions

(1) The power supply and cost review shall be conducted not less than once a year for the purpose of evaluating the Power Supply Cost Recovery Plan filed by the Company and to authorize appropriate Power Supply Cost Recovery Factors. Contemporaneously with its Power Supply Cost Recovery Plan, the Company shall file a 5-year forecast of the power supply requirements of its customers, its anticipated sources of supply and projections of Power Supply Costs.

(2) Not more than 45 days following the last day of each billing month in which a Power Supply Cost Recovery Factor has been applied to customers' bills, the Company shall file with the Commission a detailed statement for that month of the revenues recorded pursuant to the Power Supply Cost Recovery Factor and the allowance for cost of power included in the base rates established in the latest Commission order for the Company, and the cost of power supply.

(3) All revenues collected pursuant to the Power Supply Cost Recovery Factors and the allowance for power included in the base rates are subject to annual reconciliation proceedings.

**(Continued on Sheet No. C-37.00)**

**(Continued from Sheet No. C-51.00)**

**C10. RENEWABLE ENERGY PLAN (REP) (Contd)**

**C10.5 Pilot Solar Program**

The purpose of this rule is to develop and test programs to enable the development of Michigan's renewable energy resources. The Pilot Solar Program (Solar Program) is a voluntary program intended to further the deployment of solar energy in Michigan and meet customer demand. The Solar Program will consist of up to 10 MW of large scale solar facilities. The Company will extend the pilot program to follow the PA 342 2016 Amendatory Act for a period of three years following Commission approval of this tariff in docket No. U-18231. The Company will own and maintain all facilities under this pilot and/or contract with Independent Power Producers for the solar energy output of facilities located within Consumers Energy's electric distribution service area.

Eligible customers will have an opportunity to subscribe to the Solar Program. A subscription is equal to 0.5 kW of solar energy. Customers may subscribe to more than one subscription; however, a customer's total subscriptions shall not exceed the customer's Annual Net Usage. A subscribed customer will receive a Solar Energy Credit for the subscription's percentage of the solar energy generated in the Solar Program. This Solar Energy Credit includes the energy and capacity value of the program production as defined herein, and avoided line losses. The Company will retire the Renewable Energy Credits (REC), as defined in Public Act 295 of 2008 and in compliance with MCL 460.1011.

A. Definitions

Annual Net Usage - the average annual kWh usage or the annual Imputed Customer Usage in kWhs if enrolled in Net Metering.

Long Term Program Capacity Value - the product of the Zonal Resource Credits for the facilities, as determined by Mid-Continent Independent System Operator (MISO), and 75% of the applicable MISO published Cost of New Entry for the resource zone in the lower peninsula of Michigan, adjusted annually.

Long Term Program Energy Value - the kWh production of the Solar Program at each hourly interval, multiplied by the hourly day ahead Locational Marginal Price (LMP) at the CONS.CETR pricing node, adjusted for applicable line losses.

Short Term Program Energy and Capacity Value - the monthly kWh production of the Solar Program multiplied by the fixed rate of $0.075/kWh.

Solar Energy Credit - the monthly bill credit provided to the enrolled customer based on enrollment level, program solar energy production and the value of the energy credit and capacity credit described below.

Subscription Payment - a payment to participate in the Solar Program, equal to the cost of 0.5 kW of solar capacity.

B. Customer Eligibility

Subject to any restrictions, the Solar Program is available to any Full Service customer served on Rate RSP, *RSH, RPM,* RSM, GS, GSTU, GSD, GP, GPD, EIP, and GPTU. Customers will not be eligible for the Solar Program if they have received a shutoff notice within nine months preceding their application.

**(Continued on Sheet No. C-53.00)**

**(Continued from Sheet No. C-53.00)**

**C10. RENEWABLE ENERGY PLAN (REP) (Contd)**

**C10.5 Pilot Solar Program (Contd)**

E. Solar Energy Credits

Solar Energy Credits applied to the customer's monthly bill are based on the customer's subscription level, the energy credit and the capacity credit.

The Solar Energy Credits in years one through five will be based on the Short Term Program Energy and Capacity Value and in years six through twenty-five on the sum of the Long Term Program Energy Value and the Long Term Program Capacity Value.

The Long Term Program Energy Value includes a factor to account for avoided line losses attributable to the distributed resource location on the distribution system. The avoided line loss factor is *2.38*%. This value will be revised when line losses are updated in general electric rate cases, as approved by the Commission.

Customers that chose to have the REC sold when this option was initially available will be credited quarterly. The REC credit is based on a Michigan Renewable Portfolio Standard REC value published quarterly in the Midwest Market Notes by Clear Energy Brokerage and Consulting, LLC, or successor publication, multiplied by the RECs generated. Alternatively, the REC value may be based on the actual sale of the RECs.

If the monthly Solar Energy Credit is greater than the customer's bill, the excess credit will be rolled over and applied to the next month's bill. If a Solar Energy Credit accumulates to an amount greater than $100, the Company shall pay the balance to the customer.

F. Reporting

Solar Program production data will be available on the Company's website. Each participating customer's monthly energy bill will include the Subscription Payment and Solar Energy Credit.

The Company will provide quarterly reports to the MPSC detailing the enrollment status and Solar Program production.

G. Cost Recovery

Costs will be recovered as set forth in the Commission Order in Case No. U-17752.

**(Continued on Sheet No. C-55.00)**

**(Continued from Sheet No. C-57.00)**

**C10. RENEWABLE ENERGY PLAN (REP) (Contd)**

**C10.6 Voluntary Large Customer Renewable Energy Pilot (LC-REP) Program (Contd)**

B. Monthly Rate (Contd)

(1) Billing and Credits (Contd)

(c) Administrative Charge: The customer or the customer's third party renewable energy provider is responsible for delivery and sale of renewable energy to MISO. As mutually agreed, the Company may act as the administrator of the customer's renewable energy and the customer will compensate the Company through a negotiated service contract. If the Company acts as the customer's administrator for renewable energy deliveries, then the Company will bid the customer's renewable energy into the MISO energy market at the generator node and bid the generator capacity into the MISO annual capacity auction on the customer's behalf.

C. Term and Form of Contract
The LC-REP Program shall require a written negotiated service contract. Except for the initial year in which this tariff is approved, the enrollment period is open from June through September 30th each year and the program year runs from January to December.

D. Early Termination of Contract
Customers who choose to terminate their service under Option B of the LC-REP Program early will be required to take service under the existing rate schedule for the remainder of their contract year. Customers who opted for the Company to manage their renewable energy will also be responsible for any costs to the Company not yet recovered under their negotiated service contract.

**C11. *SELF-GENERATION,* NET METERING *AND DISTRIBUTED GENERATION***

***C11.1 Self-Generation***

*A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility, but elects not to participate in the Company's Standard Offer under Rule C18, Distributed Generation Program, or Net Metering Program, may elect to sell energy to the Company under an energy-only contract. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.*

*A. Distribution Requirements for Sellers Connected to Company System*

*(1) All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall install, own, operate, and maintain all metering and auxiliary devices (including any telecommunication links, if applicable) connected to the Company System. Meters furnished, installed, and maintained by the Company shall meter generation equipment.*

*(2) Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) service. The Company will determine the particular nature of the voltage in each case.*

*(3) If the seller's QF is connected to a distribution line serving other Company customers, then the point of delivery for energy measurement purposes shall be at the high voltage side of the generating facility's isolation transformer connecting the seller's generating facility to the Company's distribution system. If the seller's generating facility is not connected to a distribution line serving other Company customers, then the point of delivery for energy measurement purposes shall be at the point at which the radial line connecting the seller's generating facility to the Company's distribution system terminates at the first substation beyond the generating facility's isolation transformer.*

**(Continued on Sheet No. C-*58.10*)**

**(Continued from Sheet No. C-58.00)**

*(4) Interval Data Meters are required for each generating unit served under this rate. For a seller in which the measurement of energy delivered to the Company is not located at the point of delivery, then electric losses as determined by the Company for losses between the energy measurement location and the point of delivery shall be deducted for billing purposes from the energy measurements thus made.*

*(5) The seller must meet the requirements contained in Rule B8., Electric Interconnection and Net Metering Standards, R 460.615 - R 460.628, for the category of generator installed. Per these standards, testing and utility approval of the interconnection and execution of a parallel operating agreement must be completed prior to the equipment operating in parallel with the distribution system of the utility. Additionally, the Company will confirm and ensure that an electric generator installation at the seller's site meets the IEEE 1547 anti-islanding requirements.*

*(6) The seller is required to obtain the characteristics of service from the Company prior to the installation of equipment. The Company shall provide the characteristics in writing upon request. In the event that the equipment proposed for connection is not compatible with these characteristics, the Company shall have no obligation to modify its distribution system or provide any monetary compensation to the seller.*

*Any service facilities shall be dedicated to the generator and shall not be shared with those providing service to any seller. The Company shall determine the characteristics of service. Should the installation of new Company distribution facilities be necessary for the equipment, all costs for the distribution facilities installed may be charged to the applicant in advance of construction as a nonrefundable contribution. If the applicant desires underground service facilities, the difference in cost between overhead and underground service facilities shall be charged to the applicant in advance of construction as a nonrefundable contribution.*

*(7) If, in the sole judgment of the Company, it appears that connection of the equipment and subsequent service through the Company's facilities may cause a safety hazard, endanger the Company facilities or the seller's equipment or to disturb the Company's service to customers and other sellers, the Company may refuse or delay connection of the equipment to its facilities.*

*A seller who contracts to sell energy to the Company on an energy-only contract is not eligible to participate in the Company's Standard Offer, Net Metering Program or its Distributed Generation Program during the term the energy-only contract is in effect. Sellers with unsatisfactory payment history on their delivery account are not eligible to participate.*

*(8) The Company may discontinue purchases during system emergencies, maintenance, and other operational circumstances.*

***Administrative Cost Charge:*** *$0.0010 per kWh purchased for generation installations with a capacity of 550 kW or less*

***Energy Purchase:***
*An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance, and other operational circumstances.*

**(Continued on Sheet No. C-*58.20*)**

**(Continued from Sheet No. C-58.10)**

**C11. *SELF-GENERATION,* NET METERING *AND DISTRIBUTED GENERATION* (Contd)**

**C11.*2* Net Metering Program**

A. The Net Metering Program is offered as authorized by 2008 PA 295 and the Commission in Case Nos. U-15787, U-15803 and U-15919.

B. Net Metering Definitions

(1) Category 1 – eligible electric generator(s) with aggregate generation of 20 kW or less that use equipment certified by a nationally recognized testing laboratory to IEEE 1547.1 testing standards and in compliance with UL 1741 scope 1.1A.

(2) Category 2 – eligible electric generator(s) with aggregate generation greater than 20 kW and not more than 150 kW.

(3) Category 3 – methane digester(s) with aggregate generation greater than 150 kW but not more than 550 kW.

(4) Eligible Electric Generator – a renewable energy system or a methane digester with a generation capacity limited to the customer's electric need and that does not exceed the following:

(i) For a renewable energy system, 150 kW of aggregate generation at a single site

(ii) For a methane digester, 550 kW of aggregate generation at a single site

(5) Full Retail Rate – the power supply and distribution components of the cost of electric service. Full Retail Rate does not include surcharges, the system access charge or other charges that are assessed on a per meter basis.

(6) Imputed Customer Usage – calculated as the sum of the metered on-site generation and the net of the bidirectional flow of power across the customer interconnection during the billing period.

(7) Modified Net Metering – a utility billing method that applies the power supply energy component of the customer's otherwise applicable tariff rate to the net of the bidirectional flow of kWh across the customer interconnection with the utility distribution system during a billing period or time-of-use period. Category 2 and Category 3 customers qualify for Modified Net Metering.

(8) Net Customer Consumption – when a positive value is the result of subtracting metered outflow from the customer from metered inflow supplied by the Company. The customer has consumed electricity in excess of what is generated on premises and returned to the Company's system.

(9) Net Excess Generation – when a negative value is the result of subtracting metered outflow from the customer from metered inflow supplied by the Company. The customer has generated and returned more electricity to the Company's system than the amount of electricity supplied by the Company to the customer's premises.

(10) *Program Capacity – maximum program limit of 1% of the Company's average Peak Demand for Full-Service Customers during the previous five calendar years. Within the Program Capacity, 0.5% is reserved for Category 1 Net Metering Customers, 0.25% is reserved for Category 2 Net Metering Customers and 0.25% is reserved for Category 3 Net Metering Customers.*

**(Continued on Sheet No. C-59.00)**

**(Continued From Sheet No. C-58.*20*)**

**C11. *SELF-GENERATION,* NET METERING *AND DISTRIBUTED GENERATION* (Contd)**

**C11.*2* Net Metering Program (Contd)**

B. Net Metering Definitions (Contd)

(*11*) Renewable Energy Resource – a resource that naturally replenishes over a human, not a geological, timeframe and that is ultimately derived from solar power, water power or wind power. Renewable energy resource does not include petroleum, nuclear, natural gas, or coal. A renewable energy resource comes from the sun or from thermal inertia of the earth and minimizes the output of toxic material in the conversion of the energy and includes, but is not limited to, all of the following:

(i) Biomass
(ii) Solar and solar thermal energy
(iii) Wind energy
(iv) Kinetic energy of moving water, including the following:
  (a) waves, tides or currents
  (b) water released through a dam
(v) Geothermal energy
(vi) Municipal solid waste
(vii) Landfill gas produced by municipal solid waste

(*12*) True Net Metering – a utility billing method that applies the full retail rate to the net of the bidirectional flow of kWh across the customer interconnection with the utility distribution system during a billing period or time-of-use period. Category 1 customers with a system capable of generating 20 kW or less qualify for True Net Metering.

C. Net Metering Program Availability

The Net Metering Program is available for eligible Net Metering customers beginning with the first day of the August 2009 Bill Month. *Net Metering Program participation is contingent upon available Program Capacity under the authorized cap for each Category. Electronic Interconnection Applications for the Net Metering Program will be accepted until 4:59 P.M. Eastern Standard Time on January 2, 2021. Corresponding payments for electronic applications and hard copy applications must be postmarked no later than January 15, 2021. Applications received after the Category specific Program Capacity has been met, and before 4:59 P.M. Eastern Standard Time on January 2, 2021, will be added to the Net Metering Program waitlist.*

The Net Metering Program is voluntary and is available on a first come, first served basis until the nameplate capacity of all participating generators is equal to the maximum program limit of 1.0% of the Company's *average* peak demand for Full-Service customers during the previous *five* calendar year*s*. Within the Program Capacity, 0.5% is reserved for Category 1 Net Metering customers, 0.25% is reserved for Category 2 Net Metering customers and 0.25% is reserved for Category 3 Net Metering customers.

D. Customer Eligibility

In order to be eligible to participate in the Net Metering Program, customers must generate a portion or all of their own retail electricity requirements with an Eligible Electric Generator which utilizes a Renewable Energy Resource, as defined in Rule C11.*2*.B, Net Metering Definitions.

A customer's eligibility to participate in the Net Metering Program is conditioned on the full satisfaction of any payment term or condition imposed on the customer by pre-existing contracts or tariffs with the Company, including those imposed by participation in the Net Metering Program, or those required by the interconnection of the customer's Eligible Electric Generator to the Company's distribution system.

A customer eligible to participate in the Net Metering Program will be placed into the appropriate Net Metering Category based on the aggregate nameplate capacity of the Eligible Electric Generator(s) located on the customer's premises.

**(Continued on Sheet No. C-60.00)**

**(Continued From Sheet No. C-59.00)**

**C11. *SELF-GENERATION,* NET METERING *AND DISTRIBUTED GENERATION* (Contd)**

**C11.*2* Net Metering Program (Contd)**

D. Customer Eligibility (Contd)

(1) A Category 1 Net Metering customer has one or more Eligible Electric Generators with an aggregate nameplate capacity of 20 kW or less that use equipment certified by a nationally recognized testing laboratory to IEEE 1547.1 testing standards and is in compliance with UL 1741 scope 1.1A located on the customer's premises and metered at a single point of contact.

(2) A Category 2 Net Metering customer has one or more Eligible Electric Generators with an aggregate nameplate capacity greater than 20 kW but not more than 150 kW located on the customer's premises and metered at a single point of contact.

(3) A Category 3 Net Metering customer has one or more methane digesters with an aggregate nameplate capacity greater than 150 kW but not more than 550 kW located on the customer's premises and metered at a single point of contact.

E. Customer Billing and Net Excess Generation Credit

(1) Category 1 Customers

(a) Full Service Customers

(i) The customer will be billed at the Full Retail Rate, plus surcharges, Power Plant Securitization Charges and Power Supply Cost Recovery (PSCR) Factor on Net Customer Consumption for the billing month.

(ii) The customer will be credited at the Full Retail Rate on Net Excess Generation for the billing month. The credit shall appear on the bill for the following billing period and shall be used to offset total utility charges on that bill. Any excess credit not used to offset total utility charges will be carried forward to subsequent billing periods. Net Excess Generation Credit is non-transferrable. In months when the customer has zero Net Customer Consumption or Net Excess Generation, all applicable surcharges will be billed on the metered inflow supplied by the Company to the customer.

(b) Retail Open Access Customers

(i) The customer will be billed for the distribution components, including applicable surcharges, and Power Plant Securitization Charges, if applicable, as stated on the customer's Retail Open Access Rate Schedule on Net Customer Consumption for the billing month.

(ii) The Retail Open Access customer will be credited for distribution components as stated on the ROA customer's otherwise applicable Company Full Service Rate Schedule on Net Excess Generation for the billing month. The credit shall appear on the bill for the following billing period and shall be used to offset utility distribution charges on that bill. Any excess credit not used to offset utility distribution charges will be carried forward to subsequent billing periods. Net Excess Generation Credit is non-transferrable. In months when the customer has zero Net Customer Consumption or Net Excess Generation, all applicable surcharges will be billed on the metered inflow delivered by the Company to the customer.

(2) Category 2 Customers

(a) Full Service Customers

(i) The customer will be billed for power supply energy components, including Power Supply Cost Recovery (PSCR) Factor, on Net Customer Consumption. The customer will be billed for distribution components, surcharges, and Power Plant Securitization Charges on metered inflow supplied by the Company to the customer. General Service Secondary Demand Rate GSD and Large General Service Primary Demand Rate GPD customers will be billed for demand based capacity charges as stated on the applicable Rate Schedule.

**(Continued on Sheet No. C-61.00)**

**(Continued From Sheet No. C-60.00)**

**C11. *SELF-GENERATION,* NET METERING *AND DISTRIBUTED GENERATION* (Contd)**

**C11.*2* Net Metering Program: (Contd)**

E. Customer Billing and Net Excess Generation Credit (Contd)

(2) Category 2 Customers (Contd)

(a) Full Service Customers (Contd)

(ii) The customer will be credited for power supply energy components on Net Excess Generation. The credit shall appear on the bill for the following billing period and shall be used to offset total power supply charges on that bill. Net Excess Generation Credit exceeding total power supply charges shall be carried forward and applied to power supply charges in subsequent billing periods. Net Excess Generation Credit is non-transferrable.

(b) Retail Open Access Customers

(i) The customer will be billed for the distribution components, including applicable surcharges, and Power Plant Securitization Charges, if applicable, as stated on the ROA customer's otherwise applicable Company Full Service Rate Schedule on metered inflow supplied by the Company to the customer. The customer will be billed for demand based capacity charges in accordance with the ROA customer's otherwise applicable Company Full Service Rate Schedule.

(ii) Retail Open Access customers will not receive distribution credit on Net Excess Generation.

(3) Category 3 Customers

(a) Full Service Customers on General Service Secondary Rate GS or General Service Primary Rate GP

(i) The customer will be billed for power supply energy components, including Power Supply Cost Recovery (PSCR) Factor, on Net Customer Consumption. The customer will be billed for surcharges, and Power Plant Securitization Charges on the metered inflow supplied by the Company to the customer. The customer will be billed for distribution components on Imputed Customer Usage.

(ii) The customer will be credited for power supply energy components on Net Excess Generation. The credit shall appear on the bill for the following billing period and shall be used to offset total power supply charges on that bill. Net Excess Generation Credit exceeding total power supply charges will be carried forward and applied to power supply charges in subsequent billing periods. Net Excess Generation Credit is non-transferrable.

(b) Full Service Customers on General Service Secondary Demand Rate GSD or Large General Service Primary Demand Rate GPD

(i) The customer will be billed for power supply components, including Power Supply Cost Recovery (PSCR) Factor, on Net Customer Consumption. The customer will be billed for surcharges, and Power Plant Securitization Charges on the metered inflow supplied by the Company to the customer. The customer will be billed for distribution components on Imputed Customer Usage. General Service Secondary Demand Rate GSD and Large General Service Primary Demand Rate GPD customers will be billed for demand based capacity charges as stated on the applicable Rate Schedule.

(ii) The customer will be credited for power supply energy components on Net Excess Generation. The credit shall appear on the bill for the following billing period and shall be used to offset total power supply charges on that bill. Net Excess Generation Credit exceeding total power supply charges will be carried forward and applied to power supply charges in subsequent billing periods. Net Excess Generation Credit is non-transferrable.

**(Continued on Sheet No. C-62.00)**

(Continued From Sheet No. C-61.00)

**C11. *SELF-GENERATION,* NET METERING *AND DISTRIBUTED GENERATION* (Contd)**

**C11.*2* Net Metering Program: (Contd)**

E. Customer Billing and Net Excess Generation Credit (Contd)

(3) Category 3 Customers (Contd)

(c) Retail Open Access Customers

(i) The customer will be billed for distribution components as stated on the ROA customer's otherwise applicable Company Full Service Rate Schedule on Imputed Customer Usage. The customer will be billed for surcharges, and Power Plant Securitization Charges, if applicable, on the metered inflow supplied by the Company to the customer. The customer will be billed for demand based capacity charges as stated on the ROA customer's otherwise applicable Company Full Service Rate Schedule.

(ii) Retail Open Access customers will not receive a distribution credit on Net Excess Generation.

No refunds shall be made for any customer contribution required under Paragraphs H, I or J of this tariff or for any other costs incurred by the customer in connection with participation in the Net Metering Program.

F. Application for Service

In order to participate in the Net Metering Program, a customer shall submit a completed Interconnection Application, including application fee of $75 and a completed Net Metering Program Application, including application fee of $25 to the Company. The Net Metering Program application fee is refundable if the customer withdraws the application prior to commencing service under the Net Metering Program.

G. Generator Requirements

The Eligible Electric Generator(s) must be located on the customer's premises, serving only the customer's premises and must be intended primarily to offset a portion or all of the customer's requirement for electricity.

The customer's requirement for electricity shall be determined by one of the following methods:

(1) The customer's annual energy usage, measured in kWh, during the previous 12-month period
(2) When metered demand is available, the maximum integrated hourly demand measured in kW during the previous 12-month period
(3) In instances where complete and correct data is not available or where the customer is making changes on-site that will affect total usage, the Company and the customer shall mutually agree on a method to determine the customer's electric requirement for electricity.

The aggregate capacity of Eligible Electric Generators shall be determined by one of the following methods:

(1) Aggregate nameplate capacity of the generator(s)
(2) Aggregate projected annual kWh output of the generator(s)

The customer is required to provide the Company with a capacity rating in kW of the generating unit and a projected monthly and annual Kilowatt-hour output of the generating unit when completing the Company's Net Metering Application.

The customer need not be the owner or operator of the eligible generation equipment, but is ultimately responsible for ensuring compliance with all technical, engineering and operational requirements suitable for the Company's distribution system.

(Continued on Sheet No. C-63.00)

**(Continued From Sheet No. C-62.00)**

**C11. *SELF-GENERATION,* NET METERING *AND DISTRIBUTED GENERATION* (Contd)**

**C11.*2* Net Metering Program: (Contd)**

H. Generator Interconnection Requirements

The requirements for interconnecting a generator with the Company's facilities are contained in Rule B8., Electric Interconnection and Net Metering Standards, the Michigan Electric Utility Generator Interconnection Requirements and the Company's Generator Interconnection Supplement to Michigan Electric Utility Generator Interconnection Requirements. All such interconnection requirements must be met prior to the effective date of a customer's participation in the Net Metering Program. The customer must sign an Interconnection and Operating Agreement with the Company and fulfill all requirements as specified in the Agreement. A customer with a system capable of generating more than 20 kW shall pay actual interconnection costs associated with participating in the Net Metering Program, subject to limits established by the Michigan Public Service Commission.

I. Metering Requirements

Metering requirements shall be specified by the Company, as detailed below. All metering, including the generator meter where applicable, must be capable of recording all parameters metered on the customer's otherwise applicable tariff rate, for both Full Service and Retail Open Access customers.

(1) Category 1 Metering Requirements

The Company will utilize a meter capable of measuring the flow of energy in both directions. At the Company's option, either the customer's existing meter will be used or a single meter with separate registers capable of measuring power flow in each direction will be installed. If the existing meter is used, the Company shall test and calibrate the meter to ensure accuracy in both directions. If a meter is installed, the Company shall provide the metering equipment without cost to the customer. The customer may purchase a meter from the Company to measure generator output. The customer shall be responsible for installation and maintenance of the generator meter if purchased. The Company has no obligation to read the generator meter.

(2) Category 2 Metering Requirements

The Company will utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide such functionality, the Company shall provide metering equipment without cost to the customer.

(3) Category 3 Metering Requirements

The Company will utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide such functionality, the customer shall pay the costs incurred. Metering costs must be paid in full prior to participation in the Net Metering Program.

**(Continued on Sheet No. C-64.00)**

**(Continued From Sheet No. C-63.00)**

**C11.** ***SELF-GENERATION,* NET METERING *AND DISTRIBUTED GENERATION* (Contd)**

**C11.*2* Net Metering Program: (Contd)**

J. Distribution Line Extension and/or Extraordinary Facilities

The Company reserves the right to make special contractual arrangements with Net Metering Program customers whose utility service requires investment in electric facilities, as authorized by the Company's Rule C1.4, Extraordinary Facility Requirements and Charges, Rule C1.6, General Provisions of Service, and Rule C6., Distribution Systems, Line Extensions and Service Connections, as set out in the Company's Electric Rate Book. The Company further reserves the right to condition a customer's participation in the Net Metering Program on a satisfactory completion of any such contractual requirements. Category 1 Net Metering customers are not responsible for incremental costs associated with participation in the Net Metering Program.

K. Customer Termination from the Net Metering Program

A participating customer may terminate participation in the Company's Net Metering Program at any time for any reason on sixty days' notice. In the event that a customer who terminates participation in the Net Metering Program wishes to re-enroll, that customer must reapply as a new program participant, subject to program size limitations, application queue and application fees.

The Company may terminate a customer from the Net Metering Program if the customer fails to maintain the eligibility requirements, fails to comply with the terms of the operating agreement, or if the customer's facilities are determined not to be in compliance with technical, engineering, or operational requirements suitable for the Company's distribution system. The Company will provide sixty days' notice to the customer prior to termination from the Net Metering Program, except in situations the Company deems dangerous or hazardous. Such notice will include the reason(s) for termination.

Upon customer termination from the Net Metering Program, any existing credit on the customer's account will either be applied to the customer's final bill or refunded to the customer. The Company will refund to the customer any remaining credit in excess of the final bill amount. Net Excess Generation Credit is non-transferrable.

L. Company Termination of the Net Metering Program

Company termination of the Net Metering Program may occur upon receipt of Commission approval.
Upon Company termination of the Net Metering Program, any existing credit on the customer's account will either be applied to the customer's final bill or refunded to the customer. The Company will refund to the customer any remaining credit in excess of the final bill amount. Net Excess Generation Credit is non-transferrable.

M. Net Metering Program Status and Evaluation Reports

The Company will submit an annual status report to the Commission Staff by March 31 of each year including Net Metering Program data for the previous 12 months, ending December 31. The Company's status report shall maintain customer confidentiality.

N. Renewable Energy Credits

Renewable Energy Credits (RECs) are owned by the customer.
The Company may purchase Renewable Energy Credits from participating Net Metering customers who are willing to sell RECs generated if the customer has a generator meter in place to accurately measure and verify generator output. REC certification costs are the responsibility of the customer.
The Company will enter into a separate agreement with the customer for the purchase of any RECs.

**(Continued on Sheet No. C-*64.10*)**

***(Continued from Sheet No. C-64.00)***

## *C11. SELF-GENERATION, NET METERING AND DISTRIBUTED GENERATION (Contd)*

### *C11.3 DISTRIBUTED GENERATION PROGRAM*

*A. The Distributed Generation Program is offered as authorized by 2008 PA 295 as amended, 1939 PA 3, as amended by 2016 PA 341, Section (6)(a)(14), and the Commission in Case No. U-20697.*

*B. Distributed Generation Definitions*

1. *A Category 1 distributed generation customer has one or more Eligible Electric Generators with an aggregate nameplate capacity of 20 kW or less that use equipment certified by a nationally recognized testing laboratory to IEEE 1547.1 testing standards and is in compliance with UL 1741 scope 1.1A located on the customer's premises and metered at a single point of contact.*
2. *A Category 2 distributed generation customer has one or more Eligible Electric Generators with an aggregate capacity greater than 20 kW but not more than 150 kW located on the customer's premises and metered at a single point of contact.*
3. *A Category 3 distributed generation customer has one or more methane digesters with an aggregate nameplate capacity greater than 150 kW but not more than 550 kW located on the customer's premises and metered at a single point of contact.*
4. *Eligible Electric Generator – a renewable energy system or a methane digester with a generation capacity limited to no more than 100% of the customer's electricity consumption for the previous 12 months and does not exceed the following:*
    a. *For a renewable energy system, 150 kW of aggregate generation at a single site*
    b. *For a methane digester, 550 kW of aggregate generation at a single site*
5. *Inflow – the metered inflow delivered by the Company to the customer during the billing month or time-based pricing period.*
6. *Outflow – the metered quantity of the customer's generation not used on site and exported to the utility during the billing month or time-based pricing period.*
7. *Program Capacity – maximum program limit of 1% of the Company's average Peak Demand for Full-Service Customers during the previous five calendar years. Within the Program Capacity, 0.5% is reserved for Category 1 Net Metering Customers, 0.25% is reserved for Category 2 Net Metering Customers and 0.25% is reserved for Category 3 Net Metering Customers.*
8. *Renewable Energy Resource – a resource that naturally replenishes over a human, not geological, timeframe and that is ultimately derived from solar power, water power, or wind power. Renewable energy resource does not include petroleum, nuclear, natural gas, or coal. A renewable energy resource comes from the sun or from thermal inertia of the earth and minimizes the output of toxic material in the conversion of the energy and includes, but is not limited to, all of the following:*
    a. *Biomass*
    b. *Solar and solar thermal energy*
    c. *Wind energy*
    d. *Kinetic energy of moving water, including the following:*
        i. *Waves, tides or currents*
        ii. *Water released through a dam*
    e. *Geothermal energy*
    f. *Thermal energy produced from a geothermal heat pump*
    g. *Any of the following cleaner energy resources:*
        i. *Municipal solid waste, including the biogenic and anthropogenic factions*
        ii. *Landfill gas produced by municipal solid waste*
        iii. *Fuel that has been manufactured in whole or significant part from waste, including, but not limited to, municipal solid waste. Fuel that meets the requirements of this subparagraph includes, but is not limited to, material that is listed under 40 CFR 241.3(b) or 241.4(a) for which a nonwasted determination is made by the United States Environmental Protection Agency pursuant to 40 CPR 241.3(c). Pet coke, hazardous waste, or scrap tires are not fuel that meeting the requirements of this subparagraph.*

***(Continued on Sheet No. C-64.20)***

***(Continued from Sheet No. C-64.10)***

***C11. SELF-GENERATION, NET METERING AND DISTRIBUTED GENERATION (Contd)***

***C11.3 DISTRIBUTED GENERATION PROGRAM (Contd)***

*C. Distributed Generation Program Availability*

*The Distributed Generation Program is available for eligible Distributed Generation customers for service rendered on and after (insert effective date of rate case order approving this tariff).*

*A customer participating in a net metering program approved by the Commission before (insert effective date of the rate case order approving this tariff) shall have the option to take service under this tariff at the time service under the terms and conditions of the previous net metering program terminates in accordance with MCL 460.1183.*

*The Distributed Generation Program is voluntary and available on a first come, first served basis for new customer participants or existing customer participants increasing their aggregate generation. The combined legacy Net Metering and DG program size is equal to 1.0% of the Company's average instate peak load for Full-Service customers during the previous 5 calendar years. Within the Program Capacity, 0.5% is reserved for Category 1 Distributed Generation customers, 0.25% is reserved for Category 2 Distributed Generation customers and 0.25% is reserved for Category 3 Distributed Generation customers. The Company shall notify the Commission upon the Program reaching capacity in any Category.*

*If an existing Net Metering customer increases the aggregate generation following the effective date of the Distributed Generation Program, all onsite generation will be subject to the terms and conditions of the Distributed Generation Program.*

*D. Customer Eligibility*

*In order to be eligible to participate in the Distributed Generation Program, customers must generate a portion or all of their own retail electricity requirements with an Eligible Electric Generator which utilizes a Renewable Energy Resource, as defined in C11.3 B, Distributed Generation Definitions.*

*A customer's eligibility to participate in the Distributed Generation Program is conditioned on the full satisfaction of any payment term or condition imposed on the customer by pre-existing contracts or tariffs with the Company, including those imposed by participation in the Distributed Generation Program, or those required by the interconnection of the customer's Eligible Electric Generator to the Company's distribution system.*

*E. Customer Billing – Category 1, 2 and 3 Customers*

*1. Inflow*

*a. Full Service Customers*
*The customer will be billed according to their retail rate schedule, plus surcharges, and Power Supply Cost Recovery (PSCR) Factor on metered Inflow for the billing period or time-based pricing period.*

*b. Retail Open Access Customers*
*The customer will be billed as stated on the customer's Retail Open Access Rate Schedule on metered Inflow for the billing period or time-based pricing period.*

*2. Customer Billing – Outflow Credit*

*The customer will be credited on Outflow for the billing period or time-based pricing period. The credit shall be applied to the current billing month and shall be used to offset power supply charges on that bill. Any excess credit not used will be carried forward to subsequent billing periods. Unused Outflow Credit from previous months will be applied to power supply charges in the current billing month, if applicable. Outflow credit is non-transferrable.*

***(Continued on Sheet No. C-64.30)***

***(Continued from Sheet No. C-64.20)***

***C11. SELF-GENERATION, NET METERING AND DISTRIBUTED GENERATION (Contd)***

***C11.3 DISTRIBUTED GENERATION PROGRAM (Contd)***

*E. Customer Billing – Category 1, 2 and 3 Customers (Cont)*

*a. Full Service Customers Outflow Credit*
*Customers will be credited per kWh or per kW of Outflow based on the power supply rates (which exclude transmission costs) of their Full Service Rate Schedule as shown below, plus the PSCR factor as shown on Tariff Sheet No. D-6.00.*

| | | |
|---|---|---|
| ***Residential Rates*** | | |
| *Summer* | *($0.119655)* | *per kWh of On-Peak Outflow between June 1 and September 30* |
| *On-Peak Basic* | *($0.080485)* | *per kWh of Off-Peak Outflow between June 1 and September 30* |
| *Rate RSP* | *($0.084785)* | *per kWh of all Outflow kWh between October 1 and May 31* |
| | | |
| | *($0.119655)* | *per kWh of On-Peak Outflow between June 1 and September 30* |
| *Smart Hours* | *($0.080485)* | *per kWh of Off-Peak Outflow between June 1 and September 30* |
| *Rate RSH* | *($0.090731)* | *per kWh of On-Peak Outflow between October 1 and May 31* |
| | *($0.082526)* | *per kWh of Off-Peak Outflow between October 1 and May 31* |
| | | |
| | *($0.119655)* | *per kWh of On-Peak Outflow between June 1 and September 30* |
| *Nighttime Savers* | *($0.092844)* | *per kWh of Off-Peak Outflow between June 1 and September 30* |
| *Rate RPM* | *($0.059543)* | *per kWh of Super Off-Peak Outflow between June 1 and September 30* |
| | *($0.090731)* | *per kWh of On-Peak Outflow between October 1 and May 31* |
| | *($0.090111)* | *per kWh of Off-Peak Outflow between October 1 and May 31* |
| | *($0.067101)* | *per kWh of Super Off-Peak Outflow between October 1 and May 31* |
| | | |
| ***Secondary Rates*** | | |
| *Rate GS* | *($0.077430)* | *per kWh of Outflow during the billing months of June through September* |
| | *($0.075793)* | *per kWh of Outflow during the billing months of October through May* |
| | | |
| *Rate GSTU[(1)]* | *($0.107369)* | *per kWh of On-Peak Outflow during the billing months of June through September* |
| | *($0.085363)* | *per kWh of Mid-Peak Outflow during the billing months of June through September* |
| | *($0.056707)* | *per kWh of Off-Peak Outflow during the billing months of June through September* |
| | *($0.087262)* | *per kWh of On-Peak Outflow during the billing months of October through May* |
| | *($0.067811)* | *per kWh of Off-Peak Outflow during the billing months of October through May* |
| | | |
| *Rate GSD[(1)]* | *($0.036126)* | *per kWh of Outflow during the billing months of June through September* |
| | *($0.033377)* | *per kWh of Outflow during the billing months of October through May* |
| | *($16.12)* | *per kW of Outflow Demand during the billing months of June through September* |
| | *($13.16)* | *per kW of Outflow Demand during the billing months of October through May* |
| | | |
| *[(1)] Outflow credit will be reduced by $0.017518 per kWh for GSTU and GSD customers participating on GIS Provision.* | | |

***(Continued on Sheet No. C-64.40)***

***(Continued from Sheet No. C-64.30)***

| ***Primary Rates*** | | |
|---|---|---|
| *Rate GP* | | |
| *Customer Voltage Level 1* | *($0.067725)* | *per kWh of outflow during the billing months of June through September* |
| | *($0.066332)* | *per kWh of outflow during the billing months of October through May* |
| *Customer Voltage Level 2* | *($0.068678)* | *per kWh of outflow during the billing months of June through September* |
| | *($0.067273)* | *per kWh of outflow during the billing months of October through May* |
| *Customer Voltage Level 3* | *($0.070169)* | *per kWh of outflow during the billing months of June through September* |
| | *($0.068741)* | *per kWh of outflow during the billing months of October through May* |
| | | |
| *Rate GPD(2)* | | |
| *Customer Voltage Level 1* | *($0.030103)* | *per kWh of On-Peak Outflow during the billing months of June through September* |
| | *($0.019387)* | *per kWh of Off-Peak Outflow during the billing months of June through September* |
| | *($19.91)* | *per kW of Outflow Demand during the billing months of June through September* |
| | *($0.024654)* | *per kWh of On-Peak Outflow during the billing months of October through May* |
| | *($0.022925)* | *per kWh of Off-Peak Outflow during the billing months of October through May* |
| | *($18.01)* | *per kW of Outflow Demand during the billing months of October through May* |
| *Customer Voltage Level 2* | *($0.030473)* | *per kWh of On-Peak Outflow during the billing months of June through September* |
| | *($0.019625)* | *per kWh of Off-Peak Outflow during the billing months of June through September* |
| | *($20.21)* | *per kW of Outflow Demand during the billing months of June through September* |
| | *($0.024957)* | *per kWh of On-Peak Outflow during the billing months of October through May* |
| | *($0.023207)* | *per kWh of Off-Peak Outflow during the billing months of October through May* |
| | *($18.28)* | *per kW of Outflow Demand during the billing months of October through May* |
| *Customer Voltage Level 3* | *($0.031072)* | *per kWh of On-Peak Outflow during the billing months of June through September* |
| | *($0.020011)* | *per kWh of Off-Peak Outflow during the billing months of June through September* |
| | *($20.66)* | *per kW of Outflow Demand during the billing months of June through September* |
| | *($0.025448)* | *per kWh of On-Peak Outflow during the billing months of October through May* |
| | *($0.023663)* | *per kWh of Off-Peak Outflow during the billing months of October through May* |
| | *($18.69)* | *per kW of Outflow Demand during the billing months of October through May* |
| *(2) For customers on Rate GPD GI Provision, On-Peak kW Outflow Credit shall be reduced by $7.00 per kW during the billing months of June through September and $6.00 per kW during the billing months of October through May.* | | |
| | | |

***(Continued on Sheet No. C-64.50)***

***(Continued from Sheet No. C-64.40)***

| | | |
|---|---|---|
| *Rate GPTU* | | |
| *Customer Voltage Level 1* | *($0.103363)* | *per kWh of High-Peak Outflow between June 1 and September 30* |
| | *($0.094190)* | *per kWh of Mid-Peak Outflow between June 1 and September 30* |
| | *($0.074474)* | *per kWh of Low-Peak Outflow between June 1 and September 30* |
| | *($0.052216)* | *per kWh of Off-Peak Outflow between June 1 and September 30* |
| | *($0.068752)* | *per kWh of High-Peak Outflow between October 1 and May 31* |
| | *($0.066481)* | *per kWh of Mid-Peak Outflow between October 1 and May 31* |
| | *($0.059877)* | *per kWh of Off-Peak Outflow between October 1 and May 31* |
| *Customer Voltage Level 2* | *($0.104822)* | *per kWh of High-Peak Outflow between June 1 and September 30* |
| | *($0.095528)* | *per kWh of Mid-Peak Outflow between June 1 and September 30* |
| | *($0.075534)* | *per kWh of Low-Peak Outflow between June 1 and September 30* |
| | *($0.052956)* | *per kWh of Off-Peak Outflow between June 1 and September 30* |
| | *($0.069699)* | *per kWh of High-Peak Outflow between October 1 and May 31* |
| | *($0.067400)* | *per kWh of Mid-Peak Outflow between October 1 and May 31* |
| | *($0.060701)* | *per kWh of Off-Peak Outflow between October 1 and May 31* |
| *Customer Voltage Level 3* | *($0.107102)* | *per kWh of High-Peak Outflow between June 1 and September 30* |
| | *($0.097615)* | *per kWh of Mid-Peak Outflow between June 1 and September 30* |
| | *($0.077187)* | *per kWh of Low-Peak Outflow between June 1 and September 30* |
| | *($0.054110)* | *per kWh of Off-Peak Outflow between June 1 and September 30* |
| | *($0.071188)* | *per kWh of High-Peak Outflow between October 1 and May 31* |
| | *($0.068844)* | *per kWh of Mid-Peak Outflow between October 1 and May 31* |
| | *($0.061996)* | *per kWh of Off-Peak Outflow between October 1 and May 31* |
| *Rate EIP* | | |
| *Customer Voltage Level 1* | *($0.103385)* | *per kWh of Critical Peak Outflow between June 1 and September 30* |
| | *($0.068923)* | *per kWh of High-Peak Outflow between June 1 and September 30* |
| | *($0.062392)* | *per kWh of Mid-Peak Outflow between June 1 and September 30* |
| | *($0.050133)* | *per kWh of Low-Peak Outflow between June 1 and September 30* |
| | *($0.033705)* | *per kWh of Off-Peak Outflow between June 1 and September 30* |
| | *($0.076009)* | *per kWh of Critical Peak Outflow between October 1 and May 31* |
| | *($0.050672)* | *per kWh of High-Peak Outflow between October 1 and May 31* |
| | *($0.048519)* | *per kWh of Mid-Peak Outflow between October 1 and May 31* |
| | *($0.042875)* | *per kWh of Off-Peak Outflow between October 1 and May 31* |
| *Customer Voltage Level 2* | *($0.104742)* | *per kWh of Critical Peak Outflow between June 1 and September 30* |
| | *($0.069828)* | *per kWh of High-Peak Outflow between June 1 and September 30* |
| | *($0.063215)* | *per kWh of Mid-Peak Outflow between June 1 and September 30* |
| | *($0.050796)* | *per kWh of Low-Peak Outflow between June 1 and September 30* |
| | *($0.034149)* | *per kWh of Off-Peak Outflow between June 1 and September 30* |
| | *($0.076987)* | *per kWh of Critical Peak Outflow between October 1 and May 31* |
| | *($0.051323)* | *per kWh of High-Peak Outflow between October 1 and May 31* |
| | *($0.049144)* | *per kWh of Mid-Peak Outflow between October 1 and May 31* |
| | *($0.043427)* | *per kWh of Off-Peak Outflow between October 1 and May 31* |
| *Customer Voltage Level 1* | *($0.106900)* | *per kWh of Critical Peak Outflow between June 1 and September 30* |
| | *($0.071267)* | *per kWh of High-Peak Outflow between June 1 and September 30* |
| | *($0.064523)* | *per kWh of Mid-Peak Outflow between June 1 and September 30* |
| | *($0.051847)* | *per kWh of Low-Peak Outflow between June 1 and September 30* |
| | *($0.034855)* | *per kWh of Off-Peak Outflow between June 1 and September 30* |
| | *($0.078550)* | *per kWh of Critical Peak Outflow between October 1 and May 31* |
| | *($0.052366)* | *per kWh of High-Peak Outflow between October 1 and May 31* |
| | *($0.050143)* | *per kWh of Mid-Peak Outflow between October 1 and May 31* |
| | *($0.044310)* | *per kWh of Off-Peak Outflow between October 1 and May 31* |

b. *Retail Open Access Customers*
*The Outflow Credit will be determined by the Retail Service Supplier*

***(Continued on Sheet No. C-64.60)***

***(Continued from Sheet No. C-64.50)***

***C11. SELF-GENERATION, NET METERING AND DISTRIBUTED GENERATION (Contd)***

***C11.3 DISTRIBUTED GENERATION PROGRAM (Contd)***

*F. Application for Service*

*In order to participate in the Distributed Generation Program, a customer shall submit completed Interconnection and Distributed Generation Program Applications, including the application fee of $50 to the Company. The application fees are non-refundable.*

*The Distributed Generation Program application fee is waived if the customer is transitioning from the Net Metering Program to the DG Program, without a system modification.*

*If a customer does not act or provide proper response to the Company on an application, when some action is required by the customer, the application will be voided by the Company after 6 months.*

*G. Generator Requirements*

*The customer's requirement for electricity shall be determined by one of the following methods:*
1. *The customer's annual energy usage, measured in kWh, during the previous 12-month period*
2. *In instances where complete and correct data is not available or where the customer is making changes on-site that will affect total usage, the Company and the customer shall mutually agree on a method to determine the customer's annual electric requirement.*

*The aggregate capacity of Eligible Electric Generators shall be determined by the aggregate projected annual kWh output of the generator(s).*

*The customer is required to provide the Company with a capacity rating in $kW_{AC}$ and $kW_{DC}$ of the generating unit and a projected monthly and annual Kilowatt-hour output of the generating unit when completing the Company's Distributed Generation Program Application.*

*The customer need not be the owner or operator of the eligible generation equipment, but is ultimately responsible for ensuring compliance with all technical, engineering, and operational requirements suitable for the Company's distribution system.*

*H. Generator Interconnection Requirements*

*The requirements for interconnecting a generator with the Company's facilities are contained in Rule B8., Electric Interconnection and Distributed Generation Standards, the Michigan Electric Utility Generator Interconnection Requirements, and the Company's Generation Interconnection Supplement to Michigan Electric Utility Generator Interconnection Requirements. All such interconnection requirements must be met prior to the effective date of a customer's participation in the Distributed Generation Program. The customer must sign an Interconnection and Operating Agreement with the Company and fulfill all requirements as specified in the Agreement. The customer shall pay actual interconnection costs associated with participating in the Distributed Generation Program, subject to limits established by the Michigan Public Service Commission.*

***(Continued on Sheet No. C-64.70)***

***(Continued from Sheet No. C-64.60)***

***C11. SELF-GENERATION, NET METERING AND DISTRIBUTED GENERATION (Contd)***

***C11.3 DISTRIBUTED GENERATION PROGRAM (Contd)***

*I. Metering Requirements*

*Metering requirements shall be specified by the Company, as detailed below.*
*All metering must be capable of recording inflow and outflow, and all parameters metered on the customer's otherwise applicable retail rate schedule, for both Full Service and Retail Open Access customers.*

*J. Distribution Line Extension and/or Extraordinary Facilities*

*The Company reserves the right to make special contractual arrangements with Distributed Generation Program customers whose utility service requires investment in electric facilities, as authorized by the Company's Rule C1.4, Extraordinary Facility Requirements and Charges, Rule C1.6, General Provisions of Service, and Rule C6., Distribution Systems, Line Extensions and Service Connections, as set out in the Company's Electric Rate Book. The Company further reserves the right to condition a customer's participation in the Distributed Generation Program on a satisfactory completion of any such contractual requirements.*

*K. Customer Termination from the Distributed Generation Program*

*A participating customer may terminate participation in the Company's Distributed Generation Program at any time for any reason on sixty days' notice. In the event that a customer who terminates participation in the Distributed Generation Program wishes to re-enroll, that customer must reapply as a new program participant, subject to program size limitations, application queue, and application fee.*

*The Company may terminate a customer from the Distributed Generation Program if the customer fails to maintain eligibility requirements, fails to comply with the terms of the operating agreement, or if the customer's facilities are determined not to be in compliance with technical, engineering, or operational requirements suitable for the Company's distribution system. The Company will provide sixty days' notice to the customer prior to termination from the Distributed Generation Program, except in situations the Company deems dangerous or hazardous. Such notice will include reason(s) for termination.*

*Upon customer termination from the Distributed Generation Program, any existing credit on the customer's account will either be applied to the customer's final bill or refunded to the customer. The Company will refund to the customer any remaining credit in excess of the final bill amount. Distributed Generation Program credit is non-transferrable.*

*L. Company Termination of the Distributed Generation Program*

*Company termination of the Distributed Generation Program may occur upon receipt of Commission approval.*

*Upon Company termination of the Distributed Generation Program, any existing credit on the customer's account will either be applied to the customer's final bill or refunded to the customer. The Company will refund to the customer any remaining credit in excess of the final bill amount. Distributed Generation Program credit is non-transferrable.*

***(Continued on Sheet No. C-64.80)***

***(Continued from Sheet No. C-64.70)***

***C11. SELF-GENERATION, NET METERING AND DISTRIBUTED GENERATION (Contd)***

***C11.3 DISTRIBUTED GENERATION PROGRAM (Contd)***

*M. Distributed Generation Program Status and Evaluation Reports*

*The Company will submit an annual status report to the Commission Staff by March 31 of each year including Distributed Generation Program data for the 12 months ending December 31. The Company's status report shall maintain customer confidentiality.*

*N. Renewable Energy Credits*

*Renewable Energy Credits (RECs) are owned by the customer.*

*The Company may, but is not obligated to, purchase Renewable Energy Credits from participating Distributed Generation Program customers who are willing to sell RECs generated if the customer has a generator meter in place to accurately measure and verify generator output. REC certification costs are the responsibility of the customer.*

*The Company will enter into a separate agreement with the customer for the purchase of any RECs.*

# SURCHARGES

| ***Rate Schedule*** | ***Electric Rate Case Deferral Surcharge (Case No. U-20697) Effective for service rendered January 1, 2021 through December 31, 2021*** | ***Financial Compensation Mechanism Surcharge (Case No. U-20697) Effective for service rendered On and after January 1, 2021*** |
|---|---|---|
| *Rate RSP* | *$0.000633/kWh* | *$0.000106/kWh* |
| *Rate RDP* | *0.000633/kWh* | *0.000106/kWh* |
| *Rate RDPR* | *0.000633/kWh* | *0.000106/kWh* |
| *Rate RSM* | *0.000633/kWh* | *0.000106/kWh* |
| *Rate GS* | *0.000555/kWh* | *0.000098/kWh* |
| *Rate GSTU* | *0.000555/kWh* | *0.000098/kWh* |
| *Rate GSD* | *0.000348/kWh* | *0.000099/kWh* |
| *Rate GP* | | |
| *Customer Voltage Level 1* | *0.000013/kWh* | *0.000079/kWh* |
| *Customer Voltage Level 2* | *0.000078/kWh* | *0.000086/kWh* |
| *Customer Voltage Level 3* | *0.000160/kWh* | *0.000091/kWh* |
| *Rate GPD* | | |
| *Customer Voltage Level 1* | *0.000009/kWh* | *0.000081/kWh* |
| *Customer Voltage Level 2* | *0.000051/kWh* | *0.000088/kWh* |
| *Customer Voltage Level 3* | *0.000105/kWh* | *0.000094/kWh* |
| *Rate GPTU* | | |
| *Customer Voltage Level 1* | *0.000010/kWh* | *0.000080/kWh* |
| *Customer Voltage Level 2* | *0.000059/kWh* | *0.000087/kWh* |
| *Customer Voltage Level 3* | *0.000121/kWh* | *0.000092/kWh* |
| *Rate EIP* | | |
| *Customer Voltage Level 1* | *0.000015/kWh* | *0.000072/kWh* |
| *Customer Voltage Level 2* | *0.000087/kWh* | *0.000078/kWh* |
| *Customer Voltage Level 3* | *0.000178/kWh* | *0.000083/kWh* |
| *Rate LTILRR* | *0.000009/kWh* | *NA* |
| *Rate GSG-2* | | |
| *Customer Voltage Level 1* | *0.000015/kWh* | *0.000089/kWh* |
| *Customer Voltage Level 2* | *0.000089/kWh* | *0.000097/kWh* |
| *Customer Voltage Level 3* | *0.000183/kWh* | *0.000102/kWh* |
| *Rate GML* | *0.002363/kWh* | *0.000111/kWh* |
| *Rate GUL* | *0.002363/kWh* | *0.000111/kWh* |
| *Rate GU-LED* | *0.002363/kWh* | *0.000111/kWh* |
| *Rate GU* | *0.000194/kWh* | *0.000096/kWh* |
| *Rate PA* | *NA* | *NA* |
| *Rate ROA-R* | *NA* | *NA* |
| *Rate ROA-S* | *NA* | *NA* |
| *Rate ROA-P* | *NA* | *NA* |

# RATE CATEGORIES AND PROVISIONS

| Description | Full Service | Retail Open Access |
|---|---|---|
| **RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP** | | |
| Residential | 1001 | Not Applicable |
| Provisions | | |
| Residential Summer On-Peak Basic With Income Assistance (RIA) * | Applicable | Not Applicable |
| Residential Summer On-Peak Basic With Senior Citizen (RSC) * | Applicable | Not Applicable |
| Peak Power Savers – Air Conditioner Peak Cycling Program | Applicable | Not Applicable |
| Peak Power Savers – Peak Reward *** | Applicable | Not Applicable |
| Peak Power Savers – Critical Peak Pricing *** | Applicable | Not Applicable |
| Residential Summer On-Peak Basic With Self-Generation (SG) ** | 1701 | Not Applicable |
| Net Metering Program | Applicable | Not Applicable |
| Green Generation Program **** | Applicable | Not Applicable |

* Provisions shall not be taken in conjunction with each other.
** Provisions shall not be taken in conjunction with the Net Metering Program.
*** Peak Reward and Critical Peak Pricing shall not be taken in conjunction with each other.
**** Closed to new customers, effective April 5, 2019.

(Continued on Sheet No. D-9.00)

## RATE CATEGORIES AND PROVISIONS

**(Continued From Sheet No. D-8.00)**

| Description | Full Service | Retail Open Access |
|---|---|---|
| **RESIDENTIAL SMART HOURS RATE RSH** | | |
| Residential | 1040 | Not Applicable |
| Provisions | | |
| Residential Smart Hours With Income Assistance (RIA) * | Applicable | Not Applicable |
| Residential Smart Hours With Senior Citizen (RSC) * | Applicable | Not Applicable |
| Peak Power Savers – Air Conditioner Peak Cycling Program | Applicable | Not Applicable |
| Peak Power Savers – Peak Reward *** | Applicable | Not Applicable |
| Peak Power Savers – Critical Peak Pricing *** | Applicable | Not Applicable |
| Residential Smart Hours With Self-Generation (SG) ** | 1702 | Not Applicable |
| Net Metering Program | Applicable | Not Applicable |
| Green Generation Program **** | Applicable | Not Applicable |
| **RESIDENTIAL NIGHTTIME SAVERS RATE RPM** | | |
| Residential | 1050 | Not Applicable |
| Provisions | | |
| Residential Nighttime Savers With Income Assistance (RIA) * | Applicable | Not Applicable |
| Residential Nighttime Savers With Senior Citizen (RSC) * | Applicable | Not Applicable |
| Residential Nighttime Savers – Plug-In Electric Vehicle Only Credit | Applicable | Not Applicable |
| Peak Power Savers – Air Conditioner Peak Cycling Program | Applicable | Not Applicable |
| Peak Power Savers – Peak Reward *** | Applicable | Not Applicable |
| Peak Power Savers – Critical Peak Pricing *** | Applicable | Not Applicable |
| Residential Nighttime Savers With Self-Generation (SG) ** | 1703 | Not Applicable |
| Net Metering Program | Applicable | Not Applicable |
| Green Generation Program **** | Applicable | Not Applicable |
| **RESIDENTIAL SECONDARY SERVICE NON-TRANSMITTING METER RATE RSM** | | |
| Residential | 1000 | Not Applicable |
| Provisions | | |
| Residential Non-Transmitting Meter With Income Assistance (RIA) * | Applicable | Applicable |
| Residential Non-Transmitting Meter With Senior Citizen (RSC) * | Applicable | Applicable |
| Green Generation Program **** | Applicable | Not Applicable |

* Provisions shall not be taken in conjunction with each other.
** Provisions shall not be taken in conjunction with the Net Metering Program.
*** Peak Reward and Critical Peak Pricing shall not be taken in conjunction with each other.
**** Closed to new customers, effective April 5, 2019.

**(Continued on Sheet No. D-10.00)**

# RATE CATEGORIES AND PROVISIONS

**(Continued From Sheet No. D-9.00)**

| Description | Full Service | Retail Open Access |
|---|---|---|
| **GENERAL SERVICE SECONDARY RATE GS** | | |
| Commercial | 1100 | 2100 |
| Commercial – Temporary Construction Service | 1999 | Not Applicable |
| Provisions | | |
| Commercial Billboards/Outdoor Advertising Signs – Dusk to Dawn | Applicable | Not Applicable |
| Commercial Billboards/Outdoor Advertising Signs – Fixed Hours of Operation | Applicable | Not Applicable |
| Commercial Miscellaneous | Applicable | Not Applicable |
| Commercial Resale | Applicable | Applicable |
| Commercial With Educational Institution (GEI) | Applicable | Applicable |
| Commercial With Self-Generation (SG) * | 1715 | Not Applicable |
| Net Metering Program | Applicable | Applicable |
| Green Generation Program ** | Applicable | Not Applicable |
| Non-Transmitting Meter Provision | Applicable | Applicable |
| **GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU** | | |
| Commercial | 1121 | Not Applicable |
| Provisions | | |
| Commercial With Educational Institution (GEI) | Applicable | Not Applicable |
| *Commercial With Interruptible (GSI)* | *Applicable* | *Not Applicable* |
| Commercial With Self-Generation (SG) * | 1716 | Not Applicable |
| Commercial Resale | Applicable | Not Applicable |
| Green Generation Program ** | Applicable | Not Applicable |
| **GENERAL SERVICE SECONDARY DEMAND RATE GSD** | | |
| Commercial | 1120 | 2120 |
| Commercial (100 kW Billing Demand Guarantee) | 1140 | 2140 |
| Provisions | | |
| Commercial Resale | Applicable | Applicable |
| Commercial With Educational Institution (GEI) | Applicable | Applicable |
| *Commercial With Interruptible (GSI)* | *Applicable* | *Not Applicable* |
| Commercial With Self-Generation (SG) * | 1725 | Not Applicable |
| Commercial (100 kW Billing Demand Guarantee) With Self-Generation (SG) * | 1735 | Not Applicable |
| Net Metering Program | Applicable | Applicable |
| Green Generation Program ** | Applicable | Not Applicable |

*Provisions shall not be taken in conjunction with the Net Metering Program.
** Closed to new customers, effective April 5, 2019.

**(Continued on Sheet No. D-11.00)**

# RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

**Availability:**

Subject to any restrictions, this rate is available to any Full Service Customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, without the specific consent of the Company.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage; or (v) Rule C5.5 – Non-Transmitting Meter Provision participants.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

**Nature of Service:**

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

**Monthly Rate:**

**Power Supply Charges:** **These charges are applicable to Full Service Customers.**

Energy Charge:

| Non-Capacity | Capacity | Total | |
|---|---|---|---|
| \$*0.055119* | \$*0.045530* | \$*0.100649* | per kWh for Off-Peak kWh between June 1 and September 30 |
| \$*0.081916* | \$*0.067740* | \$*0.149656* | per kWh for On-Peak kWh between June 1 and September 30 |
| \$*0.055841* | \$*0.044655* | \$*0.100496* | per kWh for all kWh between October 1 and May 31 |

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

**Delivery Charges:** **These charges are applicable to Full Service Customers.**

| | | |
|---|---|---|
| System Access Charge: | \$*8.00* | per customer per month |
| Distribution Charge: | \$*0.055826* | per kWh for all kWh |

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

**(Continued on Sheet No. D-15.00)**

# RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

**(Continued From Sheet No. D-14.00)**

**Monthly Rate: (Contd)**

**Income Assistance Service Provision (RIA):**

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2, Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.102, Definitions; A to F. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

**Delivery Charges: These charges are applicable to Full Service Customers.**

Income Assistance Credit: $(*8.00*) per customer per month

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

***Low Income Assistance Credit (LIAC):***

*Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need chosen from one or more of the following eligibility criteria:*

1. *Customers with an approved critical care certification where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months, as verified by an authorized State, Federal or community agency.*
2. *Customers who are enrolled in the Company's Consumers Affordable Resource for Energy (CARE) program.*
3. *Customers who have received a Home Heating Credit in the previous 12 months.*
4. *Customers whose total household income does not exceed 150% of the Federal Poverty level as verified by an authorized State, Federal or community agency.*

*The monthly credit for LIAC shall be applied as follows:*
*Low Income Assistance Credit: $(30.00) per meter per month*

*If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable , and confirmation of qualification is required for each annual period of participation.*

*Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.*

**Senior Citizen Service Provision (RSC):**

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

**Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.**

Senior Citizen Credit: $(*4.00*) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

**(Continued on Sheet D-15.*10*)**

# RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

**(Continued From Sheet No. D-15.00)**

**Peak Power Savers:**

Customers can elect to participate in the Air Conditioning Peak Cycling Program and the Peak Reward Program as described in this tariff. When a customer participated in both programs, the customer's incremental energy savings earned under the Peak Reward is compared to the Peak Power Savers – Air Conditioning Peak Cycling Program Credit. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program. *The Company reserves the right to call test events between October 1 and May 31 for customers participating in Peak Power Savers Programs.*

**Air Conditioner Peak Cycling Program:**
A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers – Air Conditioner Peak Cycling Program for load management of eligible electric central air conditioning, central heat pump, or other qualifying electric equipment. Customer eligibility to participate is determined solely by the Company. The Company will accept a customer's central air conditioning, central heat pump, and other qualifying electric equipment under this program only if it has the capability to be controlled by the Company. Load Management of a customer's swimming pool pump is permitted under this program only if the customer is allowing Load Management of their air conditioner or heat pump unit. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. *When Load Management equipment is installed at a premises, future customers will be auto-enrolled into the Peak Power Savers-Air Conditioner Peak Cycling Program. Upon move in, the customer will be notified confirming participation in the Peak Power Savers-Air Conditioner Peak Cycling Program and will have 30 days to opt out.* Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers – Air Conditioner Peak Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – Air Conditioner Peak Cycling Program.

The monthly credit for the Peak Power Savers Program shall be applied as follows:

**Power Supply Charges: These charges are applicable to Full Service Customers.**

| | | |
|---|---|---|
| Peak Power Savers – Air Conditioner Peak Cycling Credit: | $(8.00) | per customer per month during the billing months of June – September |

**(Continued on Sheet No. D-16.00)**

## RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

**(Continued From Sheet No. D-15.*10*)**

**Monthly Rate: (Contd)**

**Peak Power Savers: (Contd)**

**Peak Reward:**

Participating customers are able to manage electric costs by reducing load during critical peak events. The Company may call up to fourteen critical peak events between June 1 and September 30 *and up to five critical peak events between October 1 and May 31*. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers will be credited the Peak Reward per kWh of incremental energy reductions.

**Power Supply Charges: These charges are applicable to Full Service Customers.**

Peak Reward: $(*1.00*) per kWh of incremental energy reduction during a critical peak event

**Critical Peak Price:**

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers will be charged the Critical Peak Price per kWh consumed during the critical peak event.

**Power Supply Charges: These charges are applicable to Full Service Customers.**

| | | |
|---|---|---|
| Critical Peak Price: | $*1.00* | per kWh of energy consumed during a critical peak event between June 1 and September 30 |
| Off-Peak Discount: | $(*0.018259*) | per kWh of Off-Peak kWh between June 1 and September 30 |

**(Continued on Sheet No. D-17.00)**

# RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

**(Continued From Sheet No. D-16.00)**

**Monthly Rate: (Contd)**

**Self-Generation (SG):**

*To be eligible for Self-Generation, a* Customer with a generating installation operating in parallel with the Company's system, *must meet the requirements described in Rule C 11.1., Self-Generation.*

**Net Metering Program:**

The Net Metering Program is available to any eligible customer as described in Rule C 11.*2*., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.*2*.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C 11.*2*., Net Metering Program.

***Distributed Generation Program:***

*The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.*

*A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.*

**Green Generation Program:**

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

**(Continued on Sheet No. D-18.00)**

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# RESIDENTIAL SMART HOURS RATE RSH

**Availability:**

The Residential Smart Hour Rate will be available on a date to be announced by the Company.

Subject to any restrictions, this rate is available to any Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, maintain and own the required equipment at the customers' premises at the Company's request. By selecting this rate schedule, the customer agrees to provide an email address. Electric consumption is billed using on-peak and off-peak periods year-round on the Residential Smart Hours Rate.

This rate is not available for resale purposes or for any Non-Residential usage.

**Nature of Service:**

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

**Monthly Rate:**

**Power Supply Charges: These charges are applicable to Full Service Customers.**

| | Non-Capacity | Capacity | Total | |
|---|---|---|---|---|
| Off-Peak – Summer | *$0.055119* | *$0.045530* | *$0.100649* | per kWh for all Off-Peak kWh between June 1 and September 30 |
| On-Peak – Summer | *$0.081916* | *$0.067740* | *$0.149656* | per kWh for all On-Peak kWh between June 1 and September 30 |
| Off-Peak – Winter | *$0.055019* | *$0.043086* | *$0.098105* | per kWh for all Off-Peak kWh between October 1 and May 31 |
| On-Peak – Winter | *$0.059440* | *$0.049013* | *$0.108453* | per kWh for all On-Peak kWh between October 1 and May 31 |

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

**Delivery Charges: These charges are applicable to Full Service Customers.**

| | | |
|---|---|---|
| System Access Charge: | $*8.00* | per customer per month |
| Distribution Charge: | $*0.055826* | per kWh for all kWh for a Full Service customer |

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

**Income Assistance Service Provision (RIA):**

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2, Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.102, Definitions; A to F. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

**Delivery Charges: These charges are applicable to Full Service Customers.**

Income Assistance Credit: $(*8.00*) per customer per month

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

**(Continued on Sheet No. D-37.00)**

# RESIDENTIAL SMART HOURS RATE RSH

**(Continued From Sheet No. D-36.00)**

**Monthly Rate: (Contd)**

***Low Income Assistance Credit (LIAC):***

*Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need chosen from one or more of the following eligibility criteria:*

1. *Customers with an approved critical care certification where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months, as verified by an authorized State, Federal or community agency.*
2. *Customers who are enrolled in the Company's Consumers Affordable Resource for Energy (CARE) program.*
3. *Customers who have received a Home Heating Credit in the previous 12 months.*
4. *Customers whose total household income does not exceed 150% of the Federal Poverty level as verified by an authorized State, Federal or community agency.*

*The monthly credit for LIAC shall be applied as follows:*
*Low Income Assistance Credit: $(30.00) per meter per month*

*If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable , and confirmation of qualification is required for each annual period of participation.*

*Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.*

**Senior Citizen Service Provision (RSC):**

When service is supplied to the Principle Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

**Delivery Charges: These charges are applicable to Full Service Customers.**

Senior Citizen Credit: $(*4.00*) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

**Peak Power Savers:**

Customers can elect to participate in the Air Conditioning Peak Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's incremental energy savings earned under the Peak Reward is compared to the Peak Power Savers – Air Conditioner Peak Cycling Program Credit. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program. *The Company reserves the right to call test events between October 1 and May 31 for customers participating in Peak Power Savers Programs.*

**Air Conditioner Peak Cycling Program:**

A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers – Air Conditioner Peak Cycling Program for load management of eligible electric central air conditioning, central heat pump, or other qualifying electric equipment. Customer eligibility to participate is determined solely by the Company. The Company will accept a customer's central air conditioning, central heat pump, and other qualifying electric equipment under this program only if it has the capability to be controlled by the Company. Load Management of a customer's swimming pool pump is permitted under this program only if the customer is allowing Load Management of their air conditioner or heat pump unit. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. *When Load Management equipment is installed at a premises, future customers will be auto-enrolled into the Peak Power Savers-Air Conditioner Peak Cycling Program. Upon move in, the customer will be notified confirming participation in the Peak Power Savers-Air Conditioner Peak Cycling Program and will have 30 days to opt out.* Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load Management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers – Air Conditioner Peak Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – Air Conditioner Peak Cycling Program.

The monthly credit for the Peak Power Savers Program shall be applied as follows:

**Power Supply Charges: These charges are applicable to Full Service Customers.**

| | | |
|---|---|---|
| Peak Power Savers – Air Conditioner Peak Cycling Credit: | $(8.00) | per customer per month during the billing months of June-September |

**(Continued on Sheet No. D-38.00)**

# RESIDENTIAL SMART HOURS RATE RSH

**(Continued From Sheet No. D-37.00)**

**Monthly Rate: (Contd)**

**Peak Power Savers: (Contd)**

**Peak Reward:**

Participating customers are able to manage electric costs by reducing load during critical peak events. The Company may call up to fourteen critical peak events between June 1 and September 30 *and up to five critical peak events between October 1 and May 31*. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers on will be credited the Peak Reward per kWh of incremental energy reductions.

**Power Supply Charges: These charges are applicable to Full Service Customers.**

| | | |
|---|---|---|
| Peak Reward | $(*1.00*) | per kWh of incremental energy reduction during a critical peak event |

**Critical Peak Price**

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. The Company may call up to fourteen critical peak events. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers on will be charged the Critical Peak Price per kWh consumed during the critical peak event.

**Power Supply Charges: These charges are applicable to Full Service Customers.**

| | | |
|---|---|---|
| Critical Peak Price | $*1.00* | per kWh of energy consumed during a critical peak event between June 1 and September 30 |
| Off-Peak Discount | *($0.018259)* | per kWh for Off-Peak kWh between June 1 and September 30 |

**Self-Generation (SG):**

*To be eligible for Self-Generation, a* Customer with a generating installation operating in parallel with the Company's system, *must meet the requirements described in Rule C 11.1., Self-Generation.*

**(Continued on Sheet No. D-39.00)**

# RESIDENTIAL SMART HOURS RATE RSH

**(Continued From Sheet No. D-38.00)**

**Monthly Rate: (Contd)**

**Net Metering Program**:

The Net Metering Program is available to any eligible customer as described in Rule C11.*2*., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.*2*.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.*2*., Net Metering Program.

***Distributed Generation Program:***

*The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.*

*A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.*

**Green Generation Program:**

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2., Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2., Green Generation Program.

**General Terms:**

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

**Minimum Charge:**

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non consumption based surcharges.

**Due Date and Late Payment Charge:**

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

**Schedule of On-Peak and Off-Peak Hours:**

The following schedule shall apply Monday through Friday, including weekday holidays when applicable:

Summer: June 1 through September 30
Winter: October 1 through May 31

(1) On-Peak Hours: 2:00 PM to 7:00 PM
(2) Off-Peak Hours: 7:00 PM to 2:00 PM

Saturday and Sunday are Off-Peak.

**Term and Form of Contract:**

Service under this rate shall not require a written contract.

# RESIDENTIAL NIGHTTIME SAVERS RATE RPM

**Availability**:

The Residential Nighttime Savers Rate will be available on a date to be announced by the Company.

The Residential Nighttime Savers Rate is voluntary and available to Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage or (v) customers being served under Rule C5.5 Non-Transmitting Meter Provision.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this program only under the Rules and Regulations contained in the Company's Electric Rate Book.

**Nature of Service:**

Service under this program shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

**Monthly Rate:**

**Power Supply Charges: These charges are applicable to Full Service Customers.**

**Energy Charge:**

| | Non-Capacity | Capacity | Total | |
|---|---|---|---|---|
| Super Off-Peak - Summer | *$0.042369* | *$0.030317* | *$0.072686* | per kWh for all Off-Peak kWh between June 1 and September 30 |
| Off-Peak - Summer | *$0.064633* | *$0.049800* | *$0.114433* | per kWh for all Mid-Peak kWh between June 1 and September 30 |
| On-Peak - Summer | *$0.081916* | *$0.067740* | *$0.149656* | per kWh for all On-Peak kWh between June 1 and September 30 |
| Super Off-Peak - Winter | *$0.047040* | *$0.031447* | *$0.078487* | per kWh for all Off-Peak kWh between June 1 and September 30 |
| Off-Peak - Winter | *$0.062140* | *$0.043846* | *$0.105986* | per kWh for all Off-Peak kWh between October 1 and May 31 |
| On-Peak - Winter | *$0.059440* | *$0.049013* | *$0.108453* | per kWh for all On-Peak kWh between October 1 and May 31 |

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

**Delivery Charges:** These charges are applicable to Full Service Customers.

| | | |
|---|---|---|
| System Access Charge: | $*8.00* | per customer per month |
| Distribution Charge: | *$0.055826* | per kWh for all kWh for a Full Service Customer |

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

**(Continued on Sheet No. D-41.00)**

# RESIDENTIAL NIGHTTIME SAVERS RATE RPM

**(Continued From Sheet No. D-40.00)**

**Monthly Rate: (Contd)**

**Income Assistance Service Provision (RIA):**

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.102, Definitions; A to F. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

**Delivery Charges:** These charges are applicable to Full Service Customers.

**Income Assistance Credit:** $(*8.00*) per customer per month

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

***Low Income Assistance Credit (LIAC):***

*Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need chosen from one or more of the following eligibility criteria:*

1. *Customers with an approved critical care certification where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months, as verified by an authorized State, Federal or community agency.*
2. *Customers who are enrolled in the Company's Consumers Affordable Resource for Energy (CARE) program.*
3. *Customers who have received a Home Heating Credit in the previous 12 months.*
4. *Customers whose total household income does not exceed 150% of the Federal Poverty level as verified by an authorized State, Federal or community agency.*

*The monthly credit for LIAC shall be applied as follows:*
*Low Income Assistance Credit: $(30.00) per meter per month*

*If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable , and confirmation of qualification is required for each annual period of participation.*

*Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.*

**Senior Citizen Service Provision (RSC):**

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

**Delivery Charges:** These charges are applicable to Full Service Customers.

**Senior Citizen Credit:** $(*4.00*) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

**Residential Plug-In Electric Vehicle Only Credit (REV):**

When service is supplied for Level 2 Charging of a separately metered electric vehicle, a credit shall be applied during all billing months. Electric usage for the household will be billed under the Residential Summer On-Peak Basic Rate or the Residential Smart Hours Rate.

"Level 2 Charging" is defined as voltage connection of either 240 volts or 208 volts and a maximum load of 32 amperes or 7.7 kVA at 240 volts or 6.7 kVA at 208 volts.

Vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this credit. Low-speed electric vehicles including golf carts are not eligible for this credit even if licensed to operate on public streets. The customer may be required to provide proof of registration of the electric vehicle to qualify for this credit.

**Delivery Charges:** These charges are applicable to Full Service Customers.

**Residential Plug-In Electric Vehicle Only Credit:** $(*8.00*) per customer per month

**Peak Power Savers:**

Customers can elect to participate in the Air Conditioner Peak Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's incremental energy savings earned under the Peak Reward is compared to the Peak Power Savers – Air Conditioner Peak Cycling Program Credit. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program. *The Company reserves the right to call test events between October 1 and May 31 for customers participating in Peak Power Savers Programs.*

**(Continued on Sheet No. D-42.00)**

# RESIDENTIAL NIGHTTIME SAVERS RATE RPM

**(Continued From Sheet No. D-41.00)**

**Monthly Rate: (Contd)**

**Peak Power Savers: (Contd)**

**Air Conditioner Peak Cycling Program:**

A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers – Air Conditioner Peak Cycling Program for load management of eligible electric central air conditioning, central heat pump, or other qualifying electric equipment. Customer eligibility to participate is determined solely by the Company. The Company will accept a customer's central air conditioning, central heat pump, and other qualifying electric equipment under this program only if it has the capability to be controlled by the Company. Load Management of a customer's swimming pool pump is permitted under this program only if the customer is allowing Load Management of their air conditioner or heat pump unit. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. *When Load Management equipment is installed at a premises, future customers will be auto-enrolled into the Peak Power Savers-Air Conditioner Peak Cycling Program. Upon move in, the customer will be notified confirming participation in the Peak Power Savers-Air Conditioner Peak Cycling Program and will have 30 days to opt out.* Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load Management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers – Air Conditioner Peak Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – Air Conditioner Peak Cycling Program.

The monthly credit for the Peak Power Savers Program shall be applied as follows:

**Power Supply Charges: These charges are applicable to Full Service Customers.**

| | | |
|---|---|---|
| Peak Power Savers – Air Conditioner Peak Cycling Credit: | $(8.00) | per customer per month during the billing months of June-September |

**Peak Reward:**

Participating customers are able to manage electric costs by reducing load during critical peak events. The Company may call up to fourteen critical peak events between June 1 and September 30 *and up to five critical peak events between October 1 and May 31*. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers on will be credited the Peak Reward per kWh of incremental energy reductions.

**Power Supply Charges: These charges are applicable to Full Service Customers.**

Peak Reward $(*1.00*)per kWh of incremental energy reduction during a critical peak event

**(Continued on Sheet No. D-43.00)**

# RESIDENTIAL NIGHTTIME SAVERS RATE RPM

**(Continued From Sheet No. D-42.00)**

**Monthly Rate: (Contd)**

**Peak Power Savers: (Contd)**

**Critical Peak Price**

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers on will be charged the Critical Peak Price per kWh consumed during the critical peak event.

**Power Supply Charges: These charges are applicable to Full Service Customers.**

| | | |
|---|---|---|
| Critical Peak Price | $*1.00* | per kWh of energy consumed during a critical peak event between June 1 and September 30 |
| Off-Peak Discount | *($0.018259)* | per kWh for Off-Peak kWh between June 1 and September 30 |

**Self-Generation (SG):**

*To be eligible for Self-Generation, a* Customer with a generating installation operating in parallel with the Company's system, *must meet the requirements described in Rule C 11.1., Self-Generation.*

**(Continued on Sheet No. D-44.00)**

# RESIDENTIAL NIGHTTIME SAVERS RATE RPM

**(Continued From Sheet No. D-43.00)**

**Monthly Rate: (Contd)**

***Net Metering Program:***

*The Net Metering Program is available to any eligible customer as described in Rule C 11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.2.B., Net Metering Definitions.*

*A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C 11.2., Net Metering Program.*

***Distributed Generation Program:***

*The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.*

*A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.*

**Green Generation Program:**

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

**General Terms:**

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

**Minimum Charge:**

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

**Due Date and Late Payment Charge:**

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

**Schedule of Hours:**

The following schedule shall apply Monday through Friday including weekday holidays.

Summer: June 1 through September 30
Winter: October 1 through May 31

| | | |
|---|---|---|
| (1) | Super Off-Peak Hours: | 11:00 PM to 6:00 AM |
| (2) | Off-Peak Hours: | 6:00 AM to 2:00 PM and 7:00 PM to 11:00 PM |
| (3) | On-Peak Hours: | 2:00 PM to 7:00 PM |

Saturday and Sunday are Super Off-Peak.

**Term and Form of Contract:**

Service under this rate shall not require a written contract except for the Green Generation Program participants.

# RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

**Availability:**

Subject to any restrictions, this rate is available to any customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, without the specific consent of the Company.

This rate is only available to customers electing a Non-Transmitting Meter in accordance with Rule C5.5, Non-Transmitting Meter Provision*, customers with a Non-Communicating Advanced Metering Infrastructure (AMI) Meter,* or customers determined to be eligible at the Company's sole discretion.

*A Non-Communicating AMI meter is unable to consistently transmit interval data to the Company's billing system. Non-Communicating Meters are determined at the Company's sole discretion and are subject to a minimum of one communication review per calendar year. When the meter has been determined to successfully communicate interval data, the customer will be notified and transferred to Residential Service Secondary On-Peak Summer Basic Rate RSP. The transfer to Rate RSP shall not occur between June 1 and September 30.*

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; or (iv) any other Non-Residential usage.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

**Nature of Service:**

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company will schedule meter readings on a monthly basis and attempt to obtain an actual meter reading for all tourist and/or occasional residence customers at intervals of not more than six months.

**Monthly Rate:**

**Power Supply Charges:** **These charges are applicable to Full Service customers.**

Energy Charge:

| Non-Capacity | Capacity | Total | |
|---|---|---|---|
| *$0.060524* | *$0.044655* | *$0.105179* | per kWh for the first 600 kWh per month during the billing months of June – September |
| *$0.076229* | *$0.053239* | *$0.129468* | per kWh for all kWh over 600 kWh per month during the billing months of June - September |
| *$0.055841* | *$0.044655* | *$0.100496* | per kWh for all kWh during the billing months of October-May |

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

**Delivery Charges:** **These charges are applicable to Full Service and Retail Open Access customers.**

| | | |
|---|---|---|
| System Access Charge: | $*8.00* | per customer per month |
| Distribution Charge: | *$0.055826* | per kWh for all kWh |

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

**(Continued on Sheet No. D-44.20)**

# RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

**(Continued From Sheet No. D-44.10)**

**Monthly Rate: (Contd)**

**Income Assistance Service Provision (RIA):**

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2, Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.102, Definitions; A to F. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

**Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.**

Income Assistance Credit: $(*8.00*) per customer per month

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

***Low Income Assistance Credit (LIAC):***

*Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need chosen from one or more of the following eligibility criteria:*

1. *Customers with an approved critical care certification where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months, as verified by an authorized State, Federal or community agency.*
2. *Customers who are enrolled in the Company's Consumers Affordable Resource for Energy (CARE) program.*
3. *Customers who have received a Home Heating Credit in the previous 12 months.*
4. *Customers whose total household income does not exceed 150% of the Federal Poverty level as verified by an authorized State, Federal or community agency.*

*The monthly credit for LIAC shall be applied as follows:*
*Low Income Assistance Credit: $(30.00) per meter per month*

*If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable , and confirmation of qualification is required for each annual period of participation.*

*Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.*

**(Continued on Sheet No. D-44.30)**

# RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

**(Continued From Sheet No. D-44.20)**

**Monthly Rate: (Contd)**

**Senior Citizen Service Provision (RSC):**

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

**Delivery Charges:** **These charges are applicable to Full Service and Retail Open Access customers.**

Senior Citizen Credit: $(*4.00*) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

**Green Generation Program:**

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

**Non-Transmitting Meter Provision:**

A customer who chooses a non-transmitting meter is subject to the provisions contained in Rule C5.5, Non-Transmitting Meter Provision.

**General Terms:**

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

**Minimum Charge:**

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

**Due Date and Late Payment Charge:**

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

**Term and Form of Contract:**

Service under this rate shall not require a written contract except for the Green Generation Program participants.

# GENERAL SERVICE SECONDARY RATE GS

**Availability:**

Subject to any restrictions, this rate is available to any general use customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Secondary Voltage service for any of the following: (i) standard secondary service, (ii) public potable water pumping and/or waste water system(s), or (iii) resale purposes. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers. Unmetered Billboard Service is not available to Retail Open Access service.

**Nature of Service:**

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

**Monthly Rate:**

**Power Supply Charges:** **These charges are applicable to Full Service customers.**

Energy Charge:

| Non-Capacity | Capacity | Total | |
|---|---|---|---|
| *$0.055656* | *$0.036610* | *$0.092266* | per kWh for all kWh during the billing months of June-September |
| *$0.053145* | *$0.038079* | *$0.091224* | per kWh for all kWh during the billing months of October-May |

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

**Delivery Charges:** **These charges are applicable to Full Service and Retail Open Access customers.**

| | | |
|---|---|---|
| System Access Charge: | $20.00 | per customer per month |
| Distribution Charge: | *$0.047786* | per kWh for all kWh |

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

**Billboard Service Provision:**

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be adjusted for the average number of hours used.

**(Continued on Sheet No. D-46.00)**

# GENERAL SERVICE SECONDARY RATE GS

**(Continued From Sheet No. D-45.00)**

**Monthly Rate: (Contd)**

**Resale Service Provision:**

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

**Educational Institution Service Provision (GEI):**

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

**Delivery Charges:** **These charges are applicable to Full Service and Retail Open Access Customers.**

Education Institution Credit: *($0.000782)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

**Self-Generation (SG):**

*To be eligible for Self-Generation, a* Customer with a generating installation operating in parallel with the Company's system, *must meet the requirements described in Rule C 11.1., Self-Generation.*

**(Continued on Sheet No. D-47.00)**

# GENERAL SERVICE SECONDARY RATE GS

**(Continued From Sheet No. D-46.00)**

**Monthly Rate: (Contd)**

**Net Metering Program:**

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

***Distributed Generation Program:***

*The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.*

*A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.*

**Green Generation Program:**

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C 10.2, Green Generation Program.

**Non-Transmitting Meter Provision:**

A customer who chooses a non-transmitting meter is subject to the provisions contained in Rule C5.5, Non-Transmitting Meter Provision.

**General Terms:**

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

**Minimum Charge:**

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

**Due Date and Late Payment Charge:**

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

**Term and Form of Contract:**

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, (vi) service under the Net Metering Program, or (vii) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

# GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

## Availability

Subject to any restrictions, General Service Secondary Time-of-Use Rate GSTU is available to any Full Service Customer taking service at the Company's Secondary Voltage level with advanced metering infrastructure and supporting critical systems. *Standby service shall be provided on this rate for secondary customers with solar installations equal to or greater than 150 kW.*

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers.

This rate shall not be taken in conjunction with any other Demand Response Program or Net Metering.

## Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

## Monthly Rate

**Power Supply Charges: These charges are applicable to Full Service Customers.**

Energy Charge:

| | Non-Capacity | Capacity | Total | |
|---|---|---|---|---|
| Off-Peak-Summer | *$0.040202* | *$0.027750* | *$0.067952* | per kWh for all Off-Peak kWh during the billing months of June-September |
| Mid-Peak-Summer | *$0.059788* | *$0.043000* | *$0.102788* | per kWh for all Mid-Peak kWh during the billing months of June-September |
| On-Peak-Summer | *$0.076588* | *$0.051753* | *$0.128341* | per kWh for all On-Peak kWh during the billing months of June-September |
| Off-Peak-Winter | *$0.048530* | *$0.032419* | *$0.080949* | per kWh for all Off-Peak kWh during the billing months of October-May |
| On-Peak -Winter | *$0.061455* | *$0.043392* | *$0.104847* | per kWh for all On-Peak kWh during the billing months of October-May |

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

**Delivery Charges: These charges are applicable to Full Service Customers.**

| | | |
|---|---|---|
| System Access Charge: | $20.00 | per customer per month |
| Distribution Charge: | $*0.047786* | per kWh for all kWh for a Full Service Customer |

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

**(Continued on Sheet No. D-49.00)**

# GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

**(Continued From Sheet No. D-48.00)**

**Monthly Rate (Contd)**

**Schedule of Hours**

The following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak. Holidays designated by the Company include: New Year's Day – January 1, Memorial Day – Last Monday in May, Independence Day – July 4, Labor Day – First Monday in September, Thanksgiving Day – Fourth Thursday in November and Christmas Day – December 25. Whenever January 1, July 4, or December 25 falls on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Summer Billing Months of June through September:

| | | |
|---|---|---|
| (1) | Off-Peak Hours | 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM |
| (2) | Mid-Peak Hours | 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM |
| (3) | On-Peak Hours | 2:00 PM to 6:00 PM |

Winter Billing Months of January through May and October through December:

| | | |
|---|---|---|
| (1) | Off-Peak Hours | 11:00 PM to 7:00 AM |
| (2) | On-Peak Hours | 7:00 AM to 11:00 PM |

**Resale Service Provision**

Subject to any restrictions, the provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

**Educational Institution Service Provision (GEI)**

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

**Delivery Charges - These charges are applicable to Full Service Customers.**

| | | |
|---|---|---|
| Education Institution Credit: | (*$0.000782*) | per kWh for all kWh |

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

***General Service Secondary Interruptible (GSI) Provision:***

*This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. Service to interruptible load shall be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company.*

*Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO issues a Maximum Generation Emergency Event Step 2b order or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.*

*Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized used and billed at (1) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate.*

*This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year.*

*The monthly credit for the Interruptible Service Provision shall be applied as follows:*

***Power Supply Charges - These charges are applicable to Full Service Customers.***

*Capacity Credit: These charges are applicable to Full Service Customers.*

| | | |
|---|---|---|
| *Interruptible Credit:* | *$(0.017518)* | *per kWh for all kWh* |

**Self-Generation (SG)**

*To be eligible for Self-Generation, a* Customer with a generating installation operating in parallel with the Company's system, *must meet the requirements described in Rule C 11.1., Self-Generation.*

**(Continued on Sheet No. D-50.00)**

# GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

**(Continued From Sheet No. D-49.00)**

**Monthly Rate: (Contd)**

***Distributed Generation Program:***

*The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.*

*A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.*

**Green Generation Program:**

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C 10.2, Green Generation Program.

**General Terms:**

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

**Minimum Charge:**

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

**Due Date and Late Payment Charge:**

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

**Term and Form of Contract:**

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, or (vi) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

# GENERAL SERVICE SECONDARY DEMAND RATE GSD

**Availability:**

Subject to any restrictions, this rate is available to any customer desiring Secondary Voltage service, either for general use or resale purposes, where the Peak Demand is 5 kW or more. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service, (iii) resale for lighting service, or (iv) new or expanded service for resale to residential customers.

**Nature of Service:**

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the demand and energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

**Monthly Rate:**

**Power Supply Charges: These Charges are applicable to Full Service customers.**

Peak Demand Charge:

| Non-Capacity | Capacity | Total | |
|---|---|---|---|
| *$8.18* | *$13.58* | *$21.76* | per kW for all kW of Peak Demand during the billing months of June-September |
| *$6.08* | *$12.10* | *$18.18* | per kW for all kW of Peak Demand during the billing months of October-May |

Energy Charge:

| Non-Capacity | |
|---|---|
| $*0.036126* | per kWh for all kWh during the billing months of June-September |
| $*0.033377* | per kWh for all kWh during the billing months of October-May |

This rate is subject to the Power Supply Cost Recovery (PSCR) Factors shown on Sheet No. D-6.00.

**Delivery Charges: These Charges are applicable to Full Service and Retail Open Access (ROA) customers.**

| | | |
|---|---|---|
| System Access Charge: | $30.00 | per customer per month |
| Capacity Charge: | $*0.22* | per kW for all kW of Peak Demand |
| Distribution Charge: | $*0.035027* | per kWh for all kWh |

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

**(Continued on Sheet No. D-52.00)**

# GENERAL SERVICE SECONDARY DEMAND RATE GSD

**(Continued From Sheet No. D-51.00)**

**Monthly Rate: (Contd)**

**Adjustment for Power Factor:**

*This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:*

*(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.*

*(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:*

| ***Power Factor*** | ***Penalty*** |
|---|---|
| *0.800 to 0.849* | *0.50%* |
| *0.750 to 0.799* | *1.00%* |
| *0.700 to 0.749* | *2.00%* |
| *Below 0.700* | *3% first 2 months* |

*Adjustment for Power Factor shall not be applied when the Peak Billing Demand is based on 60% of the highest On-Peak Billing Demand created during the preceding bill months of June through September or on a Minimum Peak Billing Demand.*

*(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.*

**Peak Demand:**

The Peak Demand shall be the Kilowatts (kW) supplied during the period of highest use in the billing month but not less than 60% of the highest Peak Demand created during the preceding billing months of June through September, nor less than 5 kW.

The Company reserves the right to make special determination of the Peak Demand and/or the Minimum Charge should the equipment which creates momentary high demands be included in the customer's installation.

When a customer guarantees a Peak Demand of 100 kW, the current month Peak Demand shall be the greatest of (1) the highest actual Peak Demand created during the on-peak hours in the current billing month, (2) 1/3 of the highest Peak Demand created during the off-peak hours in the current billing month, (3) 100 kW, or (4) 60% of the highest Peak Demand created during the previous billing months of June through September. For the purpose of applying the 60% provision, only the Peak Demands created after a customer guarantees 100 kW minimum shall be considered. On-peak and off-peak hours are contained in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

**Resale Service Provision:**

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

**(Continued on Sheet No. D-53.00)**

# GENERAL SERVICE SECONDARY DEMAND RATE GSD

**(Continued From Sheet No. D-52.00)**

**Monthly Rate: (Contd)**

**Educational Institution Service Provision (GEI):**

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

**Delivery Charges:** **These charges are applicable to Full Service and Retail Open Access Customers.**

Education Institution Credit: *($0.000628)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

***General Service Secondary Interruptible (GSI) Provision:***

*This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. Service to interruptible load shall be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company.*

*Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO issues a Maximum Generation Emergency Event Step 2b order or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.*

*Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate.*

*This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year.*

*The monthly credit for the Interruptible Service Provision shall be applied as follows:*

***Power Supply Charges - These charges are applicable to Full Service Customers.***

*Capacity Credit:* *These charges are applicable to Full Service Customers.*

| | | |
|---|---|---|
| *Interruptible Credit:* | *$(7.00)* | *per kW of On-Peak Billing Demand during the billing months of June-September* |
| | *$(6.00)* | *per kW of On-Peak Billing Demand during the billing months of October-May* |

**Self-Generation (SG):**

*To be eligible for Self-Generation, a* Customer with a generating installation operating in parallel with the Company's system, *must meet the requirements described in Rule C 11.1., Self-Generation.*

**(Continued on Sheet No. D-54.00)**

# GENERAL SERVICE SECONDARY DEMAND RATE GSD

**(Continued From Sheet No. D-24.00)**

**Self-Generation Provision (SG) (Contd)**

**Net Metering Program:**

The Net Metering Program is available to any eligible customer as described in Rule C 11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C 11.2., Net Metering Program.

***Distributed Generation Program:***

*The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.*

*A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.*

**Green Generation Program:**

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

**General Terms:**

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

**Minimum Charge:**

The System Access Charge included in the rate and any applicable non-consumption based surcharges.

**Due Date and Late Payment Charge:**

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

**Term and Form of Contract:**

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Net Metering program, or (v) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

# GENERAL SERVICE PRIMARY RATE GP

**Availability:**

*As of January 1, 2021, this rate is closed to new business other than for service to DCFC fast charging stations.* Subject to any restrictions, this rate is available to any customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Primary Voltage service for general use or for public potable water pumping and/or waste water system(s).

This rate is available to existing Full Service Customers with an electric generating facility interconnected at a primary voltage level utilizing General Service Primary Rate GP for standby service on or before June 7, 2012. The amount of retail usage shall be determined on an hourly basis. Customers with a generating installation are required to have an Interval Data Meter.

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for lighting service, except for temporary service for lighting installations.

**Nature of Service:**

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the energy measurements thus made.

**Monthly Rate:**

**Power Supply Charges:** **These charges are applicable to Full Service customers.**

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

| Non-Capacity | Capacity | Total | |
|---|---|---|---|
| *$0.050736* | *$0.033805* | *$0.084541* | per kWh for all kWh during the billing months of June-September |
| *$0.048540* | *$0.035143* | *$0.083683* | per kWh for all kWh during the billing months of October-May |

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

| Non-Capacity | Capacity | Total | |
|---|---|---|---|
| *$0.049699* | *$0.033015* | *$0.082714* | per kWh for all kWh during the billing months of June-September |
| *$0.047543* | *$0.034323* | *$0.081866* | per kWh for all kWh during the billing months of October-May |

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

| Non-Capacity | Capacity | Total | |
|---|---|---|---|
| *$0.049045* | *$0.032495* | *$0.081540* | per kWh for all kWh during the billing months of June-September |
| *$0.046913* | *$0.033782* | *$0.080695* | per kWh for all kWh during the billing months of October-May |

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

**(Continued on Sheet No. D-56.00)**

# GENERAL SERVICE PRIMARY RATE GP

**(Continued From Sheet No. D-55.00)**

**Monthly Rate (Contd)**

**Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) customers.**

System Access Charge: $100.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)
Distribution Charge: *$0.015276* per kWh for all kWh

Charges for Customer Voltage Level 2 (CVL2)
Distribution Charge: *$0.010098* per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL1)
Distribution Charge: *$0.006039* per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

**Adjustment for Power Factor**

This rate requires a determination of the average Power Factor maintained by the customer during the billing period . Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

| **Power Factor** | **Penalty** |
|---|---|
| 0.800 to 0.849 | 0.50% |
| 0.750 to 0.799 | 1.00% |
| 0.700 to 0.749 | 2.00% |
| Below 0.700 | 3% first 2 months |

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

**Resale Service Provision**

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

**(Continued on Sheet No. D-57.00)**

# GENERAL SERVICE PRIMARY RATE GP

**(Continued From Sheet No. D-27.10)**

**Monthly Rate (Contd)**

**Substation Ownership Credit**

Where service is supplied at a nominal voltage of more than 25,000 volts, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit.

The monthly credit for the substation ownership shall be applied as follows:

**Delivery Charges - These charges are applicable to Full Service and Retail Open Access customers.**

*Charges for Customer Voltage Level 2 (CVL 2)*
*Substation Ownership Credit: ($0.002230) per kWh for all kWh*

*Charges for Customer Voltage Level 1 (CVL 1)*
Substation Ownership Credit: *($0.000785)* per kWh for all kWh

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kWh.

**Educational Institution Service Provision (GEI)**

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

**Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.**

Educational Institution Credit: *($0.000495)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

**Self-Generation (SG):**

*To be eligible for Self-Generation, a* Customer with a generating installation operating in parallel with the Company's system, *must meet the requirements described in Rule C 11.1., Self-Generation.*

**(Continued on Sheet No. D-58.00)**

# GENERAL SERVICE PRIMARY RATE GP

**(Continued From Sheet No. D-57.00)**

**Monthly Rate (Contd)**

**Net Metering Program:**

The Net Metering Program is available to any eligible customer as described in Rule C 11.*2*., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.*2*.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C 11.*2*., Net Metering Program.

***Distributed Generation Program:***

*The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.*

*A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.*

**Green Generation Program:**

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

**General Terms:**

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

**Minimum Charge:**

The System Access charge included in the rate and any applicable non-consumption based surcharges.

**Due Date and Late Payment Charge**

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

**Term and Form of Contract**

For customers with monthly demands of 300 kW or more, all service under this rate shall require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Green Generation Program, (ii) service under the Educational Institution provision, (iii) service under the Resale Service Provision, (iv) service under the Net Metering Program, or (v) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

# LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

**Availability**

Subject to any restrictions, this rate is available to any customer desiring Primary Voltage service, either for general use or resale purposes, where the On-Peak Billing Demand is 25 kW or more. This rate is also available to any political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, for Primary Voltage service for potable water pumping and/or waste water system(s).

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is also not available for lighting service, for resale for lighting service, or for new or expanded service for resale to residential customers.

**Nature of Service**

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

**Monthly Rate:**

**Power Supply Charges:** **These charges are applicable to Full Service customers.**

Charges for Customer Voltage Level 3 (CVL3)

Demand Charge:

| Capacity | Non-Capacity | Total | |
|---|---|---|---|
| $*14.18* | $*6.48* | $*20.66* | per kW of On-Peak Billing Demand during the billing months of June-September |
| $*13.19* | $*5.50* | $*18.69* | per kW of On-Peak Billing Demand during the billing months of October-May |

Transmission Charge:

| Capacity | |
|---|---|
| $*7.31* | per kW of On-Peak Billing Demand during the billing months of June-September |
| $*6.81* | per kW of On-Peak Billing Demand during the billing months of October-May |

Energy Charge:

| Non-Capacity | |
|---|---|
| $*0.031072* | per kWh for all On-Peak kWh during the billing months of June-September |
| $*0.020011* | per kWh for all Off-Peak kWh during the billing months of June-September |
| $*0.025448* | per kWh for all On-Peak kWh during the billing months of October-May |
| $*0.023663* | per kWh for all Off-Peak kWh during the billing months of October-May |

**(Continued on Sheet No. D-60.00)**

# LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

**(Continued From Sheet No. D-59.00)**

**Monthly Rate: (Contd)**

**Power Supply Charges: These charges are applicable to Full Service customers. (Contd)**

Charges for Customer Voltage Level 2 (CVL2)

Demand Charge:

| Capacity | Non-Capacity | Total | |
|---|---|---|---|
| $*13.85* | $*6.36* | $*20.21* | per kW of On-Peak Billing Demand during the billing months of June-September |
| $*12.88* | $*5.40* | $*18.28* | per kW of On-Peak Billing Demand during the billing months of October-May |

Transmission Charge:

| Capacity | |
|---|---|
| $*7.14* | per kW of On-Peak Billing Demand during the billing months of June-September |
| $*6.65* | per kW of On-Peak Billing Demand during the billing months of October-May |

Energy Charge:

| Non-Capacity | |
|---|---|
| $*0.030473* | per kWh for all On-Peak kWh during the billing months of June-September |
| $*0.019625* | per kWh for all Off-Peak kWh during the billing months of June-September |
| $*0.024957* | per kWh for all On-Peak kWh during the billing months of October-May |
| $*0.023207* | per kWh for all Off-Peak kWh during the billing months of October-May |

Charges for Customer Voltage Level 1 (CVL1)

Demand Charge:

| Capacity | Non-Capacity | Total | |
|---|---|---|---|
| $*13.63* | $*6.28* | $*19.91* | per kW of On-Peak Billing Demand during the billing months of June-September |
| $*12.68* | $*5.33* | $*18.01* | per kW of On-Peak Billing Demand during the billing months of October-May |

Transmission Charge:

| Capacity | |
|---|---|
| $*7.03* | per kW of On-Peak Billing Demand during the billing months of June-September |
| $*6.55* | per kW of On-Peak Billing Demand during the billing months of October-May |

Energy Charge:

| Non-Capacity | |
|---|---|
| $*0.030103* | per kWh for all On-Peak kWh during the billing months of June-September |
| $*0.019387* | per kWh for all Off-Peak kWh during the billing months of June-September |
| $*0.024654* | per kWh for all On-Peak kWh during the billing months of October-May |
| $*0.022925* | per kWh for all Off-Peak kWh during the billing months of October-May |

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

**(Continued on Sheet No. D-61.00)**

# LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

**(Continued From Sheet No. D-60.00)**

**Monthly Rate: (Contd)**

**Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) customers.**

System Access Charge: $200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)

Capacity Charge: $*4.10* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL2)

Capacity Charge: $*2.40* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL1)

Capacity Charge: $*0.61* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

**Adjustment for Power Factor:**

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

| **Power Factor** | **Penalty** |
|---|---|
| 0.800 to 0.849 | 0.50% |
| 0.750 to 0.799 | 1.00% |
| 0.700 to 0.749 | 2.00% |
| Below 0.700 | 3% first 2 months |

Adjustment for Power Factor shall not be applied when the On-Peak Billing Demand is based on 60% of the highest On-Peak Billing Demand created during the preceding bill months of June through September or on a Minimum On-Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

**(Continued on Sheet No. D-62.00)**

# LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

**(Continued From Sheet No. D-31.10)**

**Monthly Rate: (Contd)**

**Maximum Demand:**

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

**On-Peak Billing Demand:**

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the current billing month, but never less than 60% of the highest on-peak billing demand of the four preceding summer billing months (June through September), nor less than 25 kW.

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

**Transmission On-Peak Billing Demand:**

The Transmission On-Peak Billing Demand for each billing month shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

**Resale Service Provision:**

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

**Substation Ownership Credit:**

Where service is supplied at a nominal voltage of more than 25,000 Volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly credit for the substation ownership shall be applied as follows:

**Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.**

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(*0.98*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $(*0.35*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer’s billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

**(Continued on Sheet No. D-63.00)**

# LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

**(Continued From Sheet No. D-62.00)**

**Monthly Rate: (Contd)**

**Aggregate Peak Demand Service Provision (GAP):**

This provision is available to any customer with 7 accounts or more who desire to aggregate their On-Peak Billing Demands for power supply billing purposes. To be eligible, each account must have a minimum average On-Peak Billing Demand of 250 kW and be located within the same billing district. The customer's aggregated accounts shall be billed under the same rate schedule and service provisions. The aggregate maximum capacity of all customers served under this provision shall be limited to 200,000 kW.

This provision commences with service rendered on and after June 20, 2008 and remains in effect until terminated by a Commission Order.

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Interval Data Meters are required for service under this provision.

The aggregated accounts shall be summarized for each interval time period registered and a comparison shall be performed to determine the on-peak time at which the summarized value of the aggregated accounts reached a maximum for the billing month. The individual aggregated accounts shall be billed for their corresponding On-Peak Billing Demand occurring at that point in time.

**Educational Institution Service Provision (GEI):**

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

**Delivery Charges:** **These charges are applicable to Full Service and Retail Open Access Customers.**

Educational Institution Credit: $(*0.000253*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

**(Continued on Sheet No. D-64.00)**

# LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

**(Continued From Sheet No. D-63.00)**

**Monthly Rate: (Contd)**

**Self-Generation (SG):**

*To be eligible for Self-Generation, a* Customer with a generating installation operating in parallel with the Company's system, *must meet the requirements described in Rule C 11.1., Self-Generation.*

**Interruptible Service Provision (GI):**

This provision is available to any customer account willing to contract for at least 500 kW of On-Peak Billing Demand as interruptible. The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed *300,000* kW *per customer*. Customers *served under Rate GPD* shall have no more than 50% of their annual On-Peak Billing Demand contracted as interruptible when contracting for more than 50,000 kW of interruptible load. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to *400,000* kW.

Consumers Energy may require the Customer to monitor and provide real-time, Internet-enabled power monitoring. If such monitoring is required, Consumers Energy will provide the metering or monitoring devices necessary, which shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

**(Continued on Sheet No. D-65.00)**

# LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

**(Continued From Sheet No. D-64.00)**

**Monthly Rate: (Contd)**

**Interruptible Service Provision (GI): (Contd)**

For billing purposes, the monthly interruptible On-Peak Billing Demand shall be billed first and discounted under this interruptible service provision. The actual On-Peak Billing Demand for the interruptible load supplied shall be credited by the amount specified under the Power Supply Charges - Interruptible Credit listed below. Subsequently all firm service used during the billing period in excess of the contracted interruptible shall be billed at the appropriate firm rate. All contracts under this provision shall be negotiated on an annual basis for the following capacity planning year (June 1 through May 31) *and the Customer must notify the Company by December 10th of each year of their desire to renew the GI provision, unless the Customer chooses to lengthen the term of their commitment (up to five years). Annual changes to the amount of interruptible kW for long term contracts are open to adjustment through December 10th of each year*. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity.

The minimum On-Peak Billing Demand that shall be billed for the interruptible portion of a customer's bill is the contracted interruptible amount. At the Company's discretion, the customer may reduce the contracted amount one time within the annual contract period.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO issues a Maximum Generation Emergency Event Step 2b order or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company’s ability to implement emergency electrical procedures as described in the Company’s Electric Rate Book including interruption of service as required to maintain system integrity.

<u>Conditions of Interruption</u>

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company’s control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company’s Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

<u>Cost of Customer Non-Interruption</u>

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

**Power Supply Charges: These charges are applicable to Full Service Customers.**

| | | |
|---|---|---|
| Interruptible Credit: | $(7.00) | per kW of On-Peak Billing Demand during the billing months of June-September |
| | $(6.00) | per kW of On-Peak Billing Demand during the billing months of October-May |

**(Continued on Sheet No. D-66.00)**

# LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

**(Continued From Sheet No. D-65.00)**

## Interruptible Service Provision – Market-Price Option (GI2)

### Availability:

This provision is available to any Full Service GPD customer account willing to *designate* at least 3,000 kW of On-Peak Billing Demand as *Defined Interruptible Capacity*. The Company reserves the right to limit the amount of *designated interruptible* load *available to any single customer*, but in no case shall it exceed 100,000 kW. The combined aggregate amount of monthly On-Peak Billing Demand subscribed under the GI and GI2 provisions shall be limited to 400,000 kW.

In the event the combined aggregate amount of monthly On-Peak Demand subscribed is less than the approved limit specified above, the Company may offer the remaining capacity, to otherwise eligible customers willing to *designate* less than the minimum amounts specified above.

The customer may choose to have the interruptible load separately metered. The customer shall bear any expense incurred by the Company in providing a separate service for the interruptible portion of an existing customer load. The customer must provide space suitable for the separate metering. Consumers Energy may require the Customer to monitor and provide real-time, Internet-enabled power monitoring. If such monitoring is required, Consumers Energy will provide the metering or monitoring devices necessary, which shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

**Contract*ed Firm* Capacity and *Defined Interruptible Capacity***

*Defined Interruptible Capacity shall be the amount of the customer's On-Peak Billing Demand at the time of the most recent annual MISO peak hour that exceeds the Customer's Firm Contract Capacity.*

*The minimum difference between the Customer's Contracted Firm Capacity and the Customer's On-Peak Billing Demand required to participate in the GI2 Provision is 3,000 kW and is subject to Company verification.*

Customers shall contract for a specified capacity in kilowatts sufficient to meet the customers' maximum interruptible requirements, but not less than the minimum contract capacity amounts, specified above. The contract capacity shall not be decreased during the term of the contract and subsequent renewal periods as long as service is required unless there is a verified reduction in connected load. Capacity disconnected from service under this provision shall not be subsequently served under any other tariff during the term of this contract and subsequent renewal periods. The Customer must notify and contract with the Company by December *10th* of each year of their desire to renew the GI2 provision and the amount of interruptible kW for the following capacity planning year (June 1 through May 31).

**Monthly Billing**

For billing purposes, the *Contracted Firm Capacity* will be billed first on Rate GPD, with the load in excess of contracted firm being billed on the GI2 charges specified in this rate schedule.

**Power Supply Charges - These charges are applicable to contracted interruptible capacity.**
The customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh.

Charges for Customer Voltage Level 3 (CVL 3)

| | |
|---|---|
| LMP Energy Charge: | MISO Real-Time LMP per kWh for all kWh |
| Capacity & Transmission Charge: | $*0.029140* per kWh for all kWh during the billing months of June-September |
| | $*0.029175* per kWh for all kWh during the billing months of October-May |

Charges for Customer Voltage Level 2 (CVL 2)

| | | |
|---|---|---|
| LMP Energy Charge: | MISO Real-Time LMP per kWh for all kWh | |
| Capacity & Transmission Charge: | $*0.025518* | per kWh for all kWh during the billing months of June-September |
| | $*0.024578* | per kWh for all kWh during the billing months of October-May |

Charges for Customer Voltage Level 1 (CVL 1)

| | | |
|---|---|---|
| LMP Energy Charge: | MISO Real-Time LMP per kWh for all kWh | |
| Capacity & Transmission Charge: | $*0.023745* | per kWh for all kWh during the billing months of June-September |
| | $*0.022748* | per kWh for all kWh during the billing months of October-May |

**(Continued on Sheet No. D-67.00)**

# LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

**(Continued From Sheet No. D-66.00)**

**Interruptible Service Provision – Market-Price Option (GI2) (Cont)**

The MISO Real-Time LMP per kWh shall be adjusted for losses based on the customer's point of metering as shown below:

| | Meter Point | |
|---|---|---|
| | High Side | Low Side |
| Customer Voltage Level 1 | 0.000% | *0.728%* |
| Customer Voltage Level 2 | *1.325%* | *2.189%* |
| Customer Voltage Level 3 | *3.329%* | *8.082%* |

**Delivery Charges – These charges are applicable to contract capacity**

Rate GPD Delivery Charges will apply to all Delivery service, including contracted capacity designated as GI2 interruptible service.

System Access Charge:

If contracted capacity is separately metered: $100.00 per additional meter installation per month

This provision is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00. as well as the System Access Charge, Delivery Charges, General Terms, Adjustment for Power Factor, Substation Ownership Credit, Minimum Charge and the Due Date and Late Payment Charge applicable to Rate GPD.

**Conditions of Interruption**

The Company will notify the customer as to the amount of total load on this rider to be curtailed. Load identified as monthly firm service and billed on Rate GPD is not considered as interruptible and does not need to be curtailed under the terms of GI2. Although actual load at time of interruption may vary from contract capacity, the total measured load on this provision shall be subject to curtailment by the Company.

The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity or have the total facility subject to interruption.

Any load designated as interruptible by the customer may require the installation and maintenance of equipment that allow the Company to remotely interrupt the customer's load. If the company determines it is required to install and maintain equipment at the customer's site to comply with any requirements associated with the GI service provision then it shall do so at the customer's expense. In addition, the customer shall also adhere to any advance notification requirements the Company deems are necessary to comply with its obligations to MISO under this provision.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO issues a Maximum Generation Emergency Event Step 2b order or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

**(Continued on Sheet No. D-68.00)**

# LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

**(Continued From Sheet No. D-67.00)**

**Interruptible Service Provision – Market-Price Option (GI2) (Cont)**

**Conditions of Interruption (Cont)**

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide notice in advance of probable interruption, and if possible, a second notice of positive interruption. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GI2 provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

**Cost of Customer Non-Interruption**

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

**Net Metering Program:**

The Net Metering Program is available to any eligible customer as described in Rule C11.*2.*, Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.*2*.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.*2.*, Net Metering Program.

***Distributed Generation Program:***

*The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.*

*A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.*

**Green Generation Program:**

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

**(Continued on Sheet No. D-69.00)**

# GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

**Availability:**

Subject to any restrictions, this General Service Primary Time-Of-Use (GPTU) Rate is available to any Full Service Customer taking service at the Company's Primary Voltage level. *Standby service shall be provided on this rate for primary customers with solar installations equal to or greater than 150 kW.*

This rate is not available for Standby service with generators that exceed 550 kW, except for solar installations, nor available for lighting service, except for temporary service for lighting installations.

**Nature of Service:**

Service under the rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a normal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling, and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

**Schedule of Hours:**

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

| | |
|---|---|
| Summer: | |
| Off-Peak Hours: | 12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM |
| Low-Peak Hours: | 6:00 AM to 12:00 PM and 7:00 PM to 11:00 PM |
| Mid-Peak Hours: | 12:00 PM to 2:00 PM and 5:00 PM to 7:00 PM |
| High-Peak Hours: | 2:00 PM to 5:00 PM |
| Winter: | |
| Off-Peak Hours: | 12:00 AM to 2:00 PM and 9:00 PM to 12:00 AM |
| Mid-Peak Hours: | 2:00 PM to 4:00 PM and 7:00 PM to 9:00 PM |
| High-Peak Hours: | 4:00 PM to 7:00 PM |

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4 or December 25 fall on a Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

**(Continued on Sheet No. D-71.00)**

# GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

**(Continued from Sheet No. D-70.00)**

**Monthly Rate:**

**Power Supply Charges:**

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

| | Non-Capacity | Capacity | Total | |
|---|---|---|---|---|
| Off-Peak-Summer | $*0.039533* | $*0.027341* | $*0.066874* | per kWh during the calendar months of June-September |
| Low-Peak-Summer | $*0.055607* | $*0.040477* | $*0.096084* | per kWh during the calendar months of June-September |
| Mid-Peak-Summer | $*0.070746* | $*0.050399* | $*0.121145* | per kWh during the calendar months of June-September |
| High-Peak-Summer | $*0.078955* | $*0.052795* | $*0.131750* | per kWh during the calendar months of June-September |
| Off-Peak-Winter | $*0.048906* | $*0.024553* | $*0.073459* | per kWh during the calendar months of October-May |
| Mid-Peak-Winter | $*0.053635* | $*0.028528* | $*0.082163* | per kWh during the calendar months of October-May |
| High-Peak-Winter | $*0.055972* | $*0.028541* | $*0.084513* | per kWh during the calendar months of October-May |

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

| | Non-Capacity | Capacity | Total | |
|---|---|---|---|---|
| Off-Peak-Summer | $*0.038719* | $*0.026703* | $*0.065422* | per kWh during the calendar months of June-September |
| Low-Peak-Summer | $*0.054458* | $*0.039532* | $*0.093990* | per kWh during the calendar months of June-September |
| Mid-Peak-Summer | $*0.069286* | $*0.049222* | $*0.118508* | per kWh during the calendar months of June-September |
| High-Peak-Summer | $*0.077332* | $*0.051562* | $*0.128894* | per kWh during the calendar months of June-September |
| Off-Peak - Winter | $*0.047916* | $*0.023980* | $*0.071896* | per kWh during the calendar months of October-May |
| Mid-Peak - Winter | $*0.052546* | $*0.027862* | $*0.080408* | per kWh during the calendar months of October-May |
| High-Peak - Winter | $*0.054839* | $*0.027874* | $*0.082713* | per kWh during the calendar months of October-May |

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

| | Non-Capacity | Capacity | Total | |
|---|---|---|---|---|
| Off-Peak-Summer | $*0.038204* | $*0.026282* | $*0.064486* | per kWh during the calendar months of June-September |
| Low-Peak-Summer | $*0.053730* | $*0.038909* | $*0.092639* | per kWh during the calendar months of June-September |
| Mid-Peak-Summer | $*0.068361* | $*0.048447* | $*0.116808* | per kWh during the calendar months of June-September |
| High-Peak-Summer | $*0.076306* | $*0.050750* | $*0.127056* | per kWh during the calendar months of June-September |
| Off-Peak - Winter | $*0.047294* | $*0.023602* | $*0.070896* | per kWh during the calendar months of October-May |
| Mid-Peak - Winter | $*0.051861* | $*0.027423* | $*0.079284* | per kWh during the calendar months of October-May |
| High-Peak - Winter | $*0.054126* | $*0.027435* | $*0.081561* | per kWh during the calendar months of October-May |

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

**Delivery Charges:**

| | | |
|---|---|---|
| System Access Charge: | $200.00 | per customer per month |

Charges for Customer Voltage Level 3 (CVL3)

| | | |
|---|---|---|
| Capacity Charge: | $*4.10* | per kW of Maximum Demand |

Charges for Customer Voltage Level 2 (CVL2)

| | | |
|---|---|---|
| Capacity Charge: | $*2.40* | per kW of Maximum Demand |

Charges for Customer Voltage Level 1 (CVL1)

| | | |
|---|---|---|
| Capacity Charge: | $*0.61* | per kW of Maximum Demand |

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

**Adjustment for Power Factor**

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

**(Continued on Sheet No. D-72.00)**

# GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

**(Continued from Sheet No. D-71.00)**

**Monthly Rate:**

**Adjustment for Power Factor (Contd)**

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

| Power Factor | Penalty |
|---|---|
| 0.800 to 0.849 | 0.50% |
| 0.750 to 0.799 | 1.00% |
| 0.700 to 0.749 | 2.00% |
| Below 0.700 | 3% first 2 months |

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

**Maximum Demand**

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

**Resale Service Provision**

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

**Substation Ownership Credit**

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

**Delivery Charges - These charges are applicable to Full Service Customers.**

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(*0.98*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $(*0.35*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

**Educational Institution Service Provision (GEI)**

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, “school” shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. “College” or “University” shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

**Delivery Charges - These charges are applicable to Full Service Customers.**

Educational Institution Credit: $ (*0.000253*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

**(Continued on Sheet No. D-73.00)**

# GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

**(Continued from Sheet No. D-71.10)**

## Monthly Rate (Contd)

### Self-Generation (SG)

*To be eligible for Self-Generation, a* Customer with a generating installation operating in parallel with the Company's system, *must meet the requirements described in Rule C 11.1., Self-Generation.*

### ***Distributed Generation Program:***

*The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.*

*A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.*

### Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

### General Terms

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

## Minimum Charge

The System Access Charge included in the rate, and any applicable non-consumption based surcharges.

### Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

### Term and Form of Contract

Service under this rate shall require a written contract with a minimum term of one year.

**(Continued on Sheet No. D-74.00)**

# ENERGY INTENSIVE PRIMARY RATE EIP

**Availability**

Subject to any restrictions, the Energy Intensive Primary Rate EIP is available to any Full Service electric metal melting customer taking service at the Company's Primary Voltage levels, where the electric load on this rate is utilized for industrial metal melting processes such as electric arc or induction furnaces or to any Full Service electric industrial customer who qualified as energy intensive as defined herein. For metal melting customers, only electric load that directly supports the process of melting metal using electricity as the main melting source qualifies as load to be served under this rate. Ancillary equipment required for the metal melting process is not intended to be served on this rate.

Existing *or former* metal melting customers taking service under the Company's Metal Melting Primary Pilot as of November 30, 2015 are eligible for service on Rate EIP. An additional 200 MW of Maximum Demand capacity will be available on a first-come, first-served basis to Full Service customers with new electric metal melting or energy intensive industrial load not previously served by the Company. To qualify as energy intensive load, the customer must demonstrate viable options to site the production outside of the state and the customer's incremental load must exceed 2 MW at a single site with an annual load factor that exceeds 70% or the customer’s incremental load must exceed 15 MW with a minimum of 75% of their total consumption occurring during Off-Peak Hours. New electric metal melting load must be separately metered. The customer must provide a special circuit or circuits in order for the Company to install separate metering.

**Nature of Service**

Service under the rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

For purposes of this rate, the appropriate measure of market price is the Real-Time LMP for the Company's retail aggregating node CONS.CETR established by the Midcontinent Independent System Operator Inc. (MISO).

**Critical Peak Event Determination**

The Company shall call a Critical Peak Event to signal either the market price has exceeded an Economic Trigger Price or a system integrity event is enacted.

A System Integrity Event is enacted when MISO declares that a Maximum Generation Emergency Event has occurred and MISO has instructed the Company to implement Load Management Measures using Load Modifying Resources and Load Management Measures - Stage 1. A System Integrity Event shall occur at any time for any duration. A Critical Peak Event caused by a System Integrity Event shall be billed at the greater of 150% of the High Peak Energy Charge or the average market price during the duration of the event.

The Summer Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 3:00 PM to 5:00 PM for the period of June 1 through September 30 of the previous year. The Summer Economic Trigger Price will be set on January 30 of each year by the Company.

The Winter Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 5:00 PM to 7:00 PM for the period of October 1 through May 31 of the previous year. The Winter Economic Trigger Price will be set on July 31 of each year by the Company.

Energy Intensive Primary Rate customers will be notified after the Summer and Winter Economic Trigger Prices are set. The Company shall endeavor to provide notice in advance of a probable System Integrity Event.

**(Continued on Sheet No. D-75.00)**

# ENERGY INTENSIVE PRIMARY RATE EIP

**(Continued from Sheet No. D-74.00)**

**Schedule of Hours:**

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

| | |
|---|---|
| Summer: | |
| Off-Peak Hours: | 12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM |
| Low-Peak Hours: | 6:00 AM to 2:00 PM and 6:00 PM to 11:00 PM |
| Mid-Peak Hours: | 2:00 PM to 3:00 PM and 5:00 PM to 6:00 PM |
| High-Peak Hours: | 3:00 PM to 5:00 PM |
| Critical Peak Hours: | *All hours* during a Critical Peak Event |
| Winter: | |
| Off-Peak Hours: | 12:00 AM to 4:00 PM and 8:00 PM to 12:00 AM |
| Mid-Peak Hours: | 4:00 PM to 5:00 PM and 7:00 PM to 8:00 PM |
| High-Peak Hours: | 5:00 PM to 7:00 PM |
| Critical Peak Hours: | *All hours* during a Critical Peak Event |

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4, or December 25 fall on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

**Monthly Rate:**

**Power Supply Charges:**

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

| | Non-Capacity | Capacity | Total | |
|---|---|---|---|---|
| Off-Peak-Summer | $*0.039141* | $*0.008228* | $*0.047369* | per kWh during the calendar months of June-September |
| Low-Peak-Summer | $*0.058545* | $*0.012857* | $*0.071402* | per kWh during the calendar months of June-September |
| Mid-Peak-Summer | $*0.072665* | $*0.015633* | $*0.088298* | per kWh during the calendar months of June-September |
| High-Peak-Summer | $*0.079597* | $*0.015993* | $*0.095590* | per kWh during the calendar months of June-September |
| Critical Peak-Summer | | | | the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June - September |
| Off-Peak - Winter | $*0.047920* | $*0.006934* | $*0.054854* | per kWh during the calendar months of October-May |
| Mid-Peak - Winter | $*0.054263* | $*0.007913* | $*0.062176* | per kWh during the calendar months of October-May |
| High-Peak - Winter | $*0.056542* | $*0.008020* | $*0.064562* | per kWh during the calendar months of October-May |
| Critical Peak-Winter | | | | the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May |

**(Continued on Sheet No. D-76.00)**

# ENERGY INTENSIVE PRIMARY RATE EIP

**(Continued from Sheet No. D-75.00)**

**Monthly Rate (Contd):**

**Power Supply Charges: (Contd)**

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

| | Non-Capacity | Capacity | Total | |
|---|---|---|---|---|
| Off-Peak-Summer | $*0.038334* | $*0.008036* | $*0.046370* | per kWh during the calendar months of June-September |
| Low-Peak-Summer | $*0.057337* | $*0.012557* | $*0.069894* | per kWh during the calendar months of June-September |
| Mid-Peak-Summer | $*0.071168* | $*0.015267* | $*0.086435* | per kWh during the calendar months of June-September |
| High-Peak-Summer | $*0.077964* | $*0.015619* | $*0.093583* | per kWh during the calendar months of June-September |
| Critical Peak-Summer | | | | the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September |
| Off-Peak - Winter | $*0.046953* | $*0.006772* | $*0.053725* | per kWh during the calendar months of October - May |
| Mid-Peak - Winter | $*0.053168* | $*0.007728* | $*0.060896* | per kWh during the calendar months of October - May |
| High-Peak - Winter | $*0.055403* | $*0.007832* | $*0.063235* | per kWh during the calendar months of October - May |
| Critical Peak-Winter | | | | the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May |

Charges for Customer Voltage Level 1(CVL1)

Energy Charge:

| | Non-Capacity | Capacity | Total | |
|---|---|---|---|---|
| Off-Peak-Summer | $*0.037825* | $*0.007909* | $*0.045734* | per kWh during the calendar months of June-September |
| Low-Peak-Summer | $*0.056571* | $*0.012359* | $*0.068930* | per kWh during the calendar months of June-September |
| Mid-Peak-Summer | $*0.070219* | $*0.015027* | $*0.085246* | per kWh during the calendar months of June-September |
| High-Peak-Summer | $*0.076931* | $*0.015373* | $*0.092304* | per kWh during the calendar months of June-September |
| Critical Peak-Summer | | | | the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September |
| Off-Peak - Winter | $*0.046346* | $*0.006665* | $*0.053011* | per kWh during the calendar months of October - May |
| Mid-Peak - Winter | $*0.052480* | $*0.007606* | $*0.060086* | per kWh during the calendar months of October - May |
| High-Peak - Winter | $*0.054687* | $*0.007709* | $*0.062396* | per kWh during the calendar months of October - May |
| Critical Peak-Winter | | | | the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May |

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

**Delivery Charges:**

System Access Charge: $200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)

Capacity Charge: $*4.10* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL2)

Capacity Charge: $*2.40* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL1)

Capacity Charge: $*0.61* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

**(Continued on Sheet No. D-77.00)**

# ENERGY INTENSIVE PRIMARY RATE EIP

**(Continued from Sheet No. D-76.00)**

**Adjustment for Power Factor:**

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

| **Power Factor** | **Penalty** |
|---|---|
| 0.800 to 0.849 | 0.50% |
| 0.750 to 0.799 | 1.00% |
| 0.700 to 0.749 | 2.00% |
| Below 0.700 | 3% first 2 months |

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

**Maximum Demand:**

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

**Substation Ownership Credit:**

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

**Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.**

<u>Charges for Customer Voltage Level 2 (CVL 2)</u>

Substation Ownership Credit: $(*0.98*) per kW of Maximum Demand

<u>Charges for Customer Voltage Level 1 (CVL 1)</u>

Substation Ownership Credit: $(*0.35*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

**Self-Generation (SG):**

*To be eligible for Self-Generation, a* Customer with a generating installation operating in parallel with the Company's system, *must meet the requirements described in Rule C 11.1., Self-Generation.*

**(Continued on Sheet No. D-78.00)**

# ENERGY INTENSIVE PRIMARY RATE EIP

**(Continued from Sheet No. D-77.00)**

***Distributed Generation Program:***

*The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.*

*A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.*

**Green Generation Programs:**

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

**General Terms:**

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

**Minimum Charge:**

The System Access Charge included in the rate and any applicable non-consumption based surcharges.

**Due Date and Late Payment Charge:**

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

**Term and Form of Contract:**

Service under this rate shall require a written contract with a minimum term of one year.

# EXPERIMENTAL ADVANCED RENEWABLE PROGRAM AR

**Availability:**

Subject to any restrictions and requirements of Rule C10.3, an individual or entity who is a delivery customer of the Company that generates electricity from a solar energy system owned by the customer and constructed using Michigan workforce labor, or using equipment made in the state of Michigan is eligible to sell power to the Company under the terms set forth in this schedule.

**Monthly Rate:**

System Access Charge: Equal to the System Access Charge of the Customer's Delivery Account but not in excess of $50, assessed per generator meter, to be paid to the Company by the customer or to be deducted from the payment to the customer by the Company

Sales of Energy to the Company that begin service no later than December 31, 2009:

$0.650 per kWh purchased by the Company payable to a Residential customer
$0.450 per kWh purchased by the Company, payable to a Non-Residential customer

Sales of Energy to the Company that begin service after December 31, 2009 but no later than October 1, 2011:

$0.525 per kWh purchased by the Company, payable to a Residential customer
$0.375 per kWh purchased by the Company, payable to a Non-Residential customer

Sales of Energy to the Company that begin service after October 1, 2011:

Price set contractually, in accordance with conditions specified in Rule C10.3.

Purchases of Energy from the Company for generator station power:

For all energy supplied by the Company, the charges shall be as provided for under the Residential Service *Secondary Non-Transmitting Meter* Rate *RSM* Rate Schedule for residential customers or the General Service Secondary Rate GS Rate Schedule, for all per kWh charges only, including additional charges such as, but not limited to, applicable surcharges, Power Plant Securitization Charges and Power Supply Cost Recovery (PSCR) Factor.

General Terms:

This program is subject to all general terms and conditions shown on Sheet No. D-1.00.

Payment of Energy Purchases:

The Company reserves the right to transfer amounts due to the Company or the customer under this schedule to an active account for energy purchases from the Company.

**Term and Form of Contract**:

Sales of energy to the Company under this schedule shall require a written contract with a minimum term of one year and a maximum term of 15 years; however, no contract term may extend beyond August 31, 2029.

# GENERAL SERVICE SELF GENERATION RATE GSG-2

**(Continued From Sheet No. D-81.00)**

**Nature of Service (Contd)**

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage above 25,000 volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Where service is supplied at a nominal voltage less than 2,400 volts and the Company elects to measure the service at a nominal voltage equal to or greater than 2,400 volts, 3% shall be deducted for billing purposes from the energy measurements thus made.

There shall be no double billing of demand under the base rate and Rate GSG-2.

**Monthly Rate**

**Standby Charges**

**Power Supply Standby Charges**

For all standby energy supplied by the Company, the customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh. In addition capacity charges will be assessed monthly, calculated using the highest 15 minute kW demand associated with Standby Service occurring during the Company's On-Peak billing hours will be multiplied by the highest contracted capacity purchased by the Company in that month, plus allocated transmission and ancillaries. The capacity charges will be prorated based on the number of On-Peak days that Standby Service was used during the billing month.

A customer with a generator(s) nameplate rating more than 550 kW must provide written notice to the Company by December 1 if they desire standby service in the succeeding calendar months of June through September. Written notice shall be submitted on Company Form 500. If the customer fails to meet this written notice requirement, the LMP shall be increased by applying a 10% adder.

**Real Power Losses**

Real Power Losses shall be measured based on the transmission loss factor of *2.10*% plus the associated meter point as listed below:

| | Meter Point | |
|---|---|---|
| | High Side | Low Side |
| Customer Voltage Level 1 | 0.000% | *0.728*% |
| Customer Voltage Level 2 | *1.325*% | *2.189*% |
| Customer Voltage Level 3 | *3.329*% | *8.082*% |

**Delivery Standby Charges**

System Access Charge:

| | | |
|---|---|---|
| Generator that does not meet or exceed load: | $100.00 | per generator installation per month |
| Generator that meets or exceeds load: | $200.00 | per generator installation per month |

Charges for Customer Voltage Level 3 (CVL 3)

Capacity Charge: $*4.10* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge: $*2.40* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge: $*0.61* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

**(Continued On Sheet No. D-83.00)**

# GENERAL SERVICE SELF GENERATION RATE GSG-2

**(Continued From Sheet No. D-82.00)**

**Monthly Rate (Contd)**

**Standby Charges (Contd)**

**Adjustment for Power Factor**

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar -hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

| **Power Factor** | **Penalty** |
|---|---|
| 0.800 to 0.849 | 0.50% |
| 0.750 to 0.799 | 1.00% |
| 0.700 to 0.749 | 2.00% |
| Below 0.700 | 3% first 2 months |

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700.Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15%penalty applies again.

**Substation Ownership Credit**

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the billed Standby Demand.

The monthly credit for the substation ownership shall be applied as follows:

**Delivery Charges**

<u>Charges for Customer Voltage Level 2 (CVL 2)</u>

Substation Ownership Credit: $(*0.98*) per kW of Maximum Demand

<u>Charges for Customer Voltage Level 1 (CVL 1)</u>

Substation Ownership Credit: $(*0.35*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer’s billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

**(Continued on Sheet No. D-84.00)**

# GENERAL SERVICE SELF GENERATION RATE GSG-2

**(Continued From Sheet No. D-83.00)**

**Monthly Rate (Contd)**

**Standby Charges (Contd)**

**Transmission Interconnect Credit**

Where standby service is provided to a non-utility electric generator located within the Company's service territory and taking power through its transmission interconnect, where the Company has no owned infrastructure other than metering, including billing grade current transformers and potential transformers, telemetry facilities and associated wiring, the following monthly credit shall be applied to the bill:

**Delivery Charges**

Transmission Interconnect Credit: $ (*0.61*) per kW of Maximum Demand

This credit shall be based on the kW after the 1% deduction has been applied to the metered kW. The credit supersedes any applicable substation ownership credit.

**Sales of Energy to the Company**

**Administrative Cost Charge**

<u>Generation installation with a capacity of over 550 kW but less than or equal to 2,000 kW</u>
As negotiated or $0.0010 per kWh purchased, at the option of the customer

<u>Generation installation with a capacity of over 2,000 kW</u>
As negotiated

**Energy Purchase:**

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule).

**General Terms**

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

**Green Generation Program**

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

**Minimum Charge**

The System Access Charge included in this Rate Schedule in addition to the customer's contracted Standby Capacity multiplied by the net of any Substation Ownership Credit and Delivery Capacity Charges of this Rate Schedule.

**Due Date and Late Payment Charge**

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

**Term and Form of Contract**

Standby service and/or sales of energy to the Company under this rate shall require a written contract with a minimum term of one year.

## *LONG TERM INDUSTRIAL LOAD RETENTION RATE - LTILRR*

***Availability:***

*Subject to any restrictions, the Long Term Industrial Load Retention Rate ("LTILRR") is available to any industrial Full Service Customer taking electric service at the Company's Primary Voltage levels that, at the time the rate contract is executed 1) has an Average Demand of at least 200,000 kW at a single site, and 2) has a minimum Annual Load Factor of 75%. Customers must execute a long-term rate contract under this Rate Schedule for a minimum of 100,000 kW of Firm Contracted Capacity, and for service at a site where the Average Demand is at least 200,000 kW at the time the rate contract is executed. Customers must enter into a contract for a term, equal to: i) the term of the designated power purchase agreement or agreements, which in no case shall be for less than 15 years for one or more designated power supply resource if the resource is a power purchase agreement or agreements, or ii) the expected remaining life of one or more designated utility-owned power supply resources.*

*A corporate officer of the customer taking service under this rate must submit a sworn affidavit stating that the customer would no longer purchase standard tariff service from the electric utility absent the customer being able to purchase power supply under the LTILRR.*

*Service under this rate is not available for intrastate facility consolidation or relocation of the customer's existing facilities, for standby service, for new or expanded service for resale or new customers or for expanded service for the benefit of parties other than the customer. Electric service provided under this Rate Schedule may not be transported off the customer's Site. A single customer shall not aggregate load from multiple sites to meet the requirements under this rate, and multiple customers shall not aggregate load to meet the requirements under this rate.*

*A customer shall be considered an industrial customer if the customer's operation meets the qualifications as determined by the NAICS as defined by the Energy Information Administration.*

*The rate contract shall require a written agreement approved by the Michigan Public Service Commission ("Commission"), specifying the terms of the electric service and shall include creditworthiness requirements to the Company's satisfaction.*

***Contracted Capacity and Annual Nominations:***

*The Maximum Contracted Capacity available to any customer under this Rate Schedule shall be specified in a written agreement approved by the Commission. The customer must nominate annually, at the time the agreement is executed, and subsequently at least eight months before the start of the subsequent Midcontinent Independent System Operator, Inc. ("MISO") Planning Year, the amount of Annual Forecast Capacity, which shall be based on the customer's highest expected Maximum Monthly Demand adjusted for known and verifiable changes. The Annual Forecast Capacity shall not exceed the Maximum Contracted Capacity. If the customer's Maximum Monthly Demand in any month exceeds the Annual Forecast Capacity for the current Planning Year, the Annual Forecast Capacity shall be increased to the Maximum Monthly Demand, up to the Maximum Contracted Capacity, and customer shall be billed for the increase in Annual Forecast Capacity for the entire current MISO Planning Year.*

*The difference between the Annual Forecast Capacity and the Maximum Contracted Capacity shall be the Reserved Capacity. The Reserved Capacity shall be made available to the customer for load growth as specified in the customer's written agreement for electric service.*

*At the time the agreement is executed, and no later than eight months prior to the start of each subsequent MISO Planning Year, the customer must specify the level of Firm Contracted Capacity, which shall not exceed the Annual Forecast Capacity. The difference between the Annual Forecast Capacity and the Firm Contracted Capacity shall be Interruptible Service Capacity, which shall be subject to the Interruptible Service Provision as specified in this Rate Schedule.*

***(Continued on Sheet No. D-84.20)***

## *LONG TERM INDUSTRIAL LOAD RETENTION RATE - LTILRR*

***(Continued From Sheet No. D-84.10)***

***Nature of Service:***

*Service under the rate shall be alternating current, 60-Hertz, three-phase Primary Voltage service. The particular nature of the voltage service provided to the customer shall be specified in a written agreement.*

*Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.*

*Line losses shall be applied to the customer's monthly metered energy and capacity values to reflect the energy consumed in moving electric power through the Transmission system and the Company's distribution system to the customer's point of delivery as determined by the Company and approved by the Commission.*

***Monthly Rate:***

| | |
|---|---|
| *System Access Charge:* | *Fixed charge per billing month as specified in the customer's written agreement for electric service* |

***Power Supply Charges:***

| | |
|---|---|
| *Capacity Charge:* | *$ per kW per month for contracted Annual Forecast Capacity as specified in the customer's written agreement for electric service* |
| *Reserved Capacity Charge:* | *$ per kW per month for the difference between the Maximum Contract Capacity and the Annual Forecast Capacity as specified in the customer's written agreement for electric service* |
| *Excess Capacity Charge:* | *$ per kW per month for Maximum Monthly Demand in excess of the Maximum Contracted Capacity based on the Power Supply Demand Charges (for Capacity and Non-Capacity) per the Large General Service Primary Demand Rate GPD Rate Schedule at the customer's applicable Customer Voltage Level* |
| *Interruptible Credit:* | *Equivalent to the Commission-approved $ per kW per month Rate GPD Interruptible Service Provision (GI) Interruptible Credit, applied to Interruptible Service Capacity, not to exceed the Capacity Charge* |
| *Energy Charge:* | *The monthly energy charges shall be based on the designated power supply resource's actual variable fuel and variable operations and maintenance expense, or the displacement costs of such expense, as applicable, associated with the customer's actual energy consumption as specified in the customer's written agreement for electric service* |

***(Continued on Sheet No. D-84.30)***

## *LONG TERM INDUSTRIAL LOAD RETENTION RATE - LTILRR*

***(Continued From Sheet No. D-84.20)***

***Power Supply Charges: (Contd)***

*Excess Energy Charge:* *$ per kWh for energy used in excess of the Maximum Contracted Capacity based on the Power Supply Energy Charges per the Rate GPD Rate Schedule at the customer's applicable Customer Voltage Level, including the applicable non-transmission PSCR Factor charges*

***Transmission Charges:***

*Transmission Charge:* *Monthly charge per billing month based on the Company's costs to acquire transmission service to serve the customer's load as specified in the customer's written agreement for electric service*

***Delivery Charges:***

*Distribution Charges:* *Monthly charge per billing month based on the dedicated distribution facilities in place to serve the customer*

*This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet No. D-7.00. This rate is not subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00*

***Interruptible Service Provision***

*The monthly credit under this Interruptible Service Provision shall be set by the Commission and shall be equivalent to the credit provided to customers receiving an Interruptible Credit under the Large General Service Primary Demand Rate GPD, Interruptible Service Provision (GI). The monthly credit available to the customer under this Interruptible Service Provision shall not exceed the Monthly Capacity Charge specified in the customer's written agreement for electric service.*

*The Company reserves the right to limit the amount of load contracted as Interruptible Service Capacity under this rate schedule, but in no case shall it exceed 300,000 kW.*

*Customers contracting for interruptible service under this rate schedule shall be required to monitor and provide real-time, Internet-enabled power monitoring. The Company will provide the metering or monitoring devices necessary, which shall be owned by the Company and provided to the customer at the Company's expense. The customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the customer's site electricity consumption and interruption event performance.*

*The interruptible load is subject to the MISO Load Modifying Resource requirements. Within 30 minutes of receiving an interruption notice from the Company, the customer shall reduce its total load level down to the Firm Contracted Capacity level or as required by the MISO partial curtailment request.*

*Any load designated as interruptible is subject to MISO requirements for Load Modifying Resources and Company shall inform customer of such MISO requirements. Interruption under this Interruptible Service Provision may occur if MISO issues a Maximum Generation Emergency Event Step 2b order or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status. Participation in the Interruptible Service Provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.*

***(Continued on Sheet No. D-84.40)***

## *LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR*

***(Continued From Sheet No. D-84.30)***

***Interruptible Service Provision (Contd)***

*Conditions of Interruption*

*Under this Interruptible Service Provision, the customer shall be interrupted at any time MISO deems it necessary to maintain system integrity. The Company shall endeavor to provide notice to the customer in advance of probable interruption by MISO. The Company shall provide the customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. Notices will be communicated by telephone to the contact numbers provided by the customer. The customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.*

*The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this Interruptible Service Provision.*

*Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3, Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this Interruptible Service Provision.*

*Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall reflect firm service capacity as provided under this rate schedule.*

*Cost of Non-Compliance with Interruption*

*Failure by customer to comply with an interruption order under this Interruptible Service Provision shall be considered as unauthorized use and billed at (i) the higher of the customer's pro rata share of any actual MISO penalties incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible Peak Billing Demand created during the interruption period in excess of the Firm Contracted Capacity or the partial curtailment requested amount, in addition to the prescribed monthly rate.*

***Adjustment for Power Factor***

*This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor.*

*A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, the 15% penalty shall apply again if the Power Factor falls below 0.700 for two consecutive months.*

***General Terms:***

*The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.*

***(Continued on Sheet No. D-84.50)***

## *LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR*

***(Continued From Sheet No. D-84.40)***

***Monthly Minimum Charge:***

*The Monthly Minimum Charge shall be the lower of the total amount due on the invoice or the sum of (i) the System Access Charge, (ii) the Distribution Charge, (iii) the monthly Capacity Charge, (iv) the monthly Reserved Capacity Charge, (v) any applicable non-consumption-based Surcharges, plus (vi) the monthly Interruptible Credit.*

***Due Date and Late Payment Charge:***

*The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.*

***Term and Form of Contract:***

*Service under this rate shall require a written agreement, approved by the Commission. Customers served under this Rate Schedule must contract for a minimum of 100,000 kW of Firm Contracted Capacity.*

***Definitions Applicable to the Long Term Industrial Load Retention Rate:***

***Annual Forecast Capacity***
*Annual Forecast Capacity is the higher of the customer's maximum forecasted amount of electric capacity nominated, or actual Maximum Monthly Demand used, by the customer during the MISO Planning Year beginning June 1 and ending May 31 of the following calendar year, subject to the limitations and adjustments as specified in the customer's written agreement.*

***Annual Load Factor***
*Annual Load Factor shall be calculated as an average of the prior 12 monthly load factors. Each monthly load factor shall be determined by dividing the customer's actual monthly kWh sales by the product of the customer's Maximum Monthly Demand times the number of hours in the month.*

***Average Demand***
*Shall mean the average of the most recent 12 monthly site Maximum Monthly Demands.*

***Capacity Charge***
*The Capacity Charge shall be the Company's levelized cost of capacity, including fixed operation and maintenance expense, associated with the designated power supply resource at the time the customer's agreement for electric service is executed, or the Company's cost of capacity, including fixed operation and maintenance expense, associated with a designated power purchase agreement or agreements.*

***Energy Charge***
*The Energy Charge shall be the Company's actual variable fuel and actual variable operation and maintenance expense based on the customer's actual energy consumption and associated with the designated power supply resource, or the Company's actual energy and capacity purchases, if any, based on the customer's actual consumption, as applicable.*

***Excess Capacity***
*The Excess Capacity is the customer's actual Maximum Monthly Demand in excess of the Maximum Contracted Capacity in any billing month.*

***(Continued on Sheet No. D-84.60)***

## *LONG TERM INDUSTRIAL LOAD RETENTION RATE - LTILRR*

***(Continued From Sheet No. D-84.50)***

***Definitions Applicable to the Long Term Industrial Load Retention Rate: (Contd)***

***Firm Contracted Capacity***

*The amount of electric capacity of at least 100,000 kW and not more than the Annual Forecast Capacity that the Company will supply to qualifying customers as specified in a written agreement that is not subject to the Interruptible Service Provision.*

***Interruptible Peak Billing Demand***

*The highest measured 15-minute interval demand in excess of the Firm Contracted Capacity that is consumed by the customer during an interruption event.*

***Interruptible Service Capacity***

*Interruptible Service Capacity is the difference between the Annual Forecast Capacity and the Firm Contracted Capacity which shall be subject to interruption per the Long Term Industrial Load Retention Rate Interruptible Service Provision.*

***Interval Data Meters***

*Interval Data Meters are meters that register customer kilowatt-hour use, peak demand, on-peak demand, and Maximum Monthly Demand.*

***Maximum Contracted Capacity***

*The maximum amount of electric capacity eligible for purchase by eligible customer under this Rate Schedule for the term of a written agreement.*

***Maximum Monthly Demand***

*The Maximum Monthly Demand shall be the highest 15-minute demand created by customer during the billing month.*

***MISO Planning Year***

*MISO Planning Year means a period extending from June 1st of a calendar year to May 31st of the following calendar year.*

***Reserved Capacity***

*The difference between the Maximum Contracted Capacity and the Annual Forecast Capacity held in reserve for future customer growth during the term of the customer's written agreement for electric service under the LTILRR*

***Site***

*An industrial site or contiguous industrial site or single commercial establishment as specified in the written agreement for electric service pursuant to the LTILRR. A site that is divided by an inland body of water or by a public highway, road, or street but that otherwise meets this definition meets the contiguous requirements.*

# GENERAL SERVICE METERED LIGHTING RATE GML

**Availability**

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways, for Primary or Secondary Voltage energy-only metered lighting service where the Company has existing distribution lines available for supplying energy for such service. Luminaires which are served under the Company's unmetered lighting rates shall not be intermixed with luminaires served under this metered lighting rate. Luminaire types in addition to those served on Rate Schedule GUL, such as light-emitting diode (LED) streetlights, may receive service under this Rate Schedule.

This rate is not available for resale purposes or for Retail Open Access Service.

**Nature of Service**

**Secondary Voltage**

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), 120/240 nominal Volt service for a minimum of ten luminaires located within a clearly defined area. Control equipment shall be furnished, owned and maintained by the Company. The customer shall furnish, install, own and maintain the rest of the equipment comprising the metered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires, protective equipment, and the supply circuits extending to the point of attachment with the Company's distribution system. The Company shall connect the customer's equipment to the Company's lines and supply the energy for its operation. All of the customer's equipment shall be subject to the Company's approval. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

**Dusk to Midnight Service**

Dusk to midnight service shall be the same as Secondary service except:

The customer shall pay the difference between the cost of the control equipment necessary for dusk to midnight service and control equipment normally installed for Secondary service. Circuits shall be arranged approximating minimum loads of 3 kW.

**Primary Voltage**

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), Primary Voltage service for actual kW demands of not less than 100 kW for each point of delivery and where the customer guarantees a minimum of 4,000 annual hours' use of the actual demand. The Company will determine the particular nature of the voltage in each case. The customer shall furnish, install, own and maintain all equipment comprising the metered lighting system including, but not limited to, controls, protective equipment, transformers and overhead or underground metered lighting circuits extending to the point of attachment with the Company's distribution system. The Company shall furnish, install, own and maintain the metering equipment and connect the customer's metered lighting circuit to its distribution system and supply the energy for operation of the customer's metered lighting system.

**Monthly Rate**

**Secondary Power Supply Charge**

Energy Charge:

| Non-Capacity | Capacity | Total | |
|---|---|---|---|
| $*0.050412* | $0.000000 | $*0.050412* | per kWh for all kWh |

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

**(Continued on Sheet No. D-86.00)**

# GENERAL SERVICE METERED LIGHTING RATE GML

**(Continued From Sheet No. D-85.00)**

**Monthly Rate (Contd)**

**Secondary Delivery Charge**

| | | |
|---|---|---|
| System Access Charge: | $10.00 | per customer per month |
| Distribution Charge: | $*0.057472* | per kWh for all kWh |

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

**Primary Power Supply Charge**

Energy Charge:

| Non-Capacity | Capacity | Total | |
|---|---|---|---|
| $*0.024740* | $0.000000 | $*0.024740* | per kWh for all kWh |

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

**Primary Delivery Charge**

| | | |
|---|---|---|
| System Access Charge: | $20.00 | per customer per month |
| Distribution Charge: | $*0.043798* | per kWh for all kWh |

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

**Net Metering Program**

The Net Metering Program is available to any eligible customer as described in Rule C11.*2*., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.*2*.B., Net Metering Program.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.*2*., Net Metering Program.

**Green Generation Program**

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

**(Continued on Sheet No. D-87.00)**

# GENERAL SERVICE UNMETERED LIGHTING RATE GUL

**(Continued From Sheet No. D-89.00)**

**Monthly Rate**

**The charge per luminaire per month shall be:**

**Nominal Rating of Lamps (One Lamp per Luminaire) (1)**

| Type of Luminaire | Watts | Watts Including Ballast (2) | Lumens | Service Charge per Luminaire (4) Non-Capacity | Capacity | Total | Fixture Charge per Luminaire (4) |
|---|---|---|---|---|---|---|---|
| Mercury Vapor (3) | 100 | 128 | 3,500 | $ *10.39* | $0.00 | $ *10.39* | $*5.00* |
| Mercury Vapor (3) | 175 | 209 | 7,500 | *16.96* | 0.00 | *16.96* | $*5.00* |
| Mercury Vapor (3) | 250 | 281 | 10,000 | *22.80* | 0.00 | *22.80* | $*5.00* |
| Mercury Vapor (3) | 400 | 458 | 20,000 | *37.16* | 0.00 | *37.16* | $*5.00* |
| Mercury Vapor (3) | 700 | 770 | 35,000 | *62.48* | 0.00 | *62.48* | $*5.00* |
| Mercury Vapor (3) | 1,000 | 1,080 | 50,000 | *87.64* | 0.00 | *87.64* | $*5.00* |
| High-Pressure Sodium (3) | 70 | 83 | 5,000 | *6.74* | 0.00 | *6.74* | $*5.00* |
| High-Pressure Sodium | 100 | 117 | 8,500 | 9.49 | 0.00 | 9.49 | $*5.00* |
| High-Pressure Sodium | 150 | 171 | 14,000 | *13.88* | 0.00 | *13.88* | $*5.00* |
| High-Pressure Sodium (3) | 200 | 247 | 20,000 | *20.04* | 0.00 | *20.04* | $*5.00* |
| High-Pressure Sodium | 250 | 318 | 24,000 | *25.80* | 0.00 | *25.80* | $*5.00* |
| High-Pressure Sodium | 400 | 480 | 45,000 | *38.95* | 0.00 | *38.95* | $*5.00* |
| Fluorescent (3) | 380 | 470 | 20,000 | *38.14* | 0.00 | *38.14* | $*5.00* |
| Incandescent (3) | 202 | 202 | 2,500 | *16.39* | 0.00 | *16.39* | $*5.00* |
| Incandescent (3) | 305 | 305 | 4,000 | *24.75* | 0.00 | *24.75* | $*5.00* |
| Incandescent (3) | 405 | 405 | 6,000 | *32.86* | 0.00 | *32.86* | $*5.00* |
| Incandescent (3) | 690 | 690 | 10,000 | *55.99* | 0.00 | *55.99* | $*5.00* |
| Metal Halide (3) | 150 | 170 | 9,750 | *13.79* | 0.00 | *13.79* | $*5.00* |
| Metal Halide (3) | 175 | 210 | 10,500 | 17.04 | 0.00 | *17.04* | $*5.00* |
| Metal Halide (3) | 250 | 290 | 15,500 | *23.53* | 0.00 | *23.53* | $*5.00* |
| Metal Halide (3) | 400 | 460 | 24,000 | *37.33* | 0.00 | *37.33* | $*5.00* |

(1) Ratings for fluorescent lighting apply to all lamps in one luminaire.

(2) Watts including ballast used for monthly billing of the Power Supply Cost Recovery (PSCR) Factor, the Power Plant Securitization Charges and surcharges.

(3) Rates apply to existing luminaires only and are not open to new business.

(4) For Customer-Owned lighting fixtures that are assessed a Service Charge (but not a Fixture Charge), the charge per luminaire represents a *21.0*% Power Supply Charge and a *79.0*% Distribution Charge.

For Company-Owned lighting fixtures that are assessed both a Service Charge and a Fixture Charge, the charge per luminaire represents a *15.1*% Power Supply Charge and a *84.9*% Distribution Charge.

For energy conservation purposes, customers may, at their option, elect to have any or all luminaires served under this rate disconnected for a period of six months or more. The charge per luminaire per month, for each disconnected luminaire, shall be 40% of the monthly rate set forth above. However, should any such disconnected luminaire be reconnected at the customer's request after having been disconnected for less than six months, the monthly rate set forth above shall apply to the period of disconnection. An $8.00 per luminaire disconnect/reconnect charge shall be made at the time of disconnection except that when the estimated disconnect/reconnect cost is significantly higher than $8.00, the estimated cost per luminaire shall be charged.

For 24-hour mercury-vapor service, the charge per luminaire shall be 125% of the foregoing rates.

**(Continued on Sheet No. D-91.00)**

# GENERAL UNMETERED *LIGHT EMITTING DIODE* LIGHTING RATE GU- *LED*

**Availability:**

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways for unmetered streetlighting service where the Company has existing distribution lines available for supplying energy for unmetered light-emitting diode (LED) *lighting* or for any Company-owned *LED* streetlighting system consisting of one or more luminaires. This rate is not available for resale purposes or for Retail Open Access Service. Installations under this rate shall require a written agreement.

**Nature of Service:**

**Company-Owned Option**

In Company-owned systems, the Company shall select, furnish, install and own all equipment for any new unmetered *LED* lighting or for any modifications to existing Company-owned equipment. The Company shall supply the energy and maintain all equipment. In areas where the Company's facilities are underground or required to be placed underground or the customer requests underground facilities, the unmetered lighting system shall be served from underground cables pursuant to the provisions contained in this Rate Schedule. In all other areas, the unmetered lighting system shall normally be served from overhead lines pursuant to the provisions contained in this Rate Schedule.

**Customer-Owned Option**

The capacity requirements of the customer-owned Unmetered *LED* Lighting served under this rate shall be determined by the Company based on verifiable documentation supplied by the customer. The Company shall have the right to test such capacity requirements. In the event that said tests show capacity requirements different from those indicated by the documentation supplied by the customer, the Company's test capacity value shall be used for billing purposes.

In customer-owned systems, control equipment shall be furnished and owned by the Company. The customer shall furnish, install and maintain the equipment comprising the unmetered *LED* lighting system including, but not limited to, poles, the overhead wires or underground cables between the luminaires and the supply circuits extending to the point of attachment with the Company's lines. The customer's *LED* lighting fixtures and equipment must be approved in advance by the Company before purchase and installation for service under this rate. The Company shall connect the customer's equipment to the Company's lines in a manner consistent with the Company's engineering standards, supply the energy and control the burning hours of the experimental lighting. Maintenance and replacement of the customer-owned equipment shall be the responsibility of the customer.

Existing unmetered installations with customer-owned fixtures on Company-owned distribution equipment must be converted to the customer-owned system described above or the Company-owned system described below to receive service under this Rate Schedule. Such installations may also be converted to a customer-owned metered system and receive service under Rate Schedule GML. Conversion costs shall be the responsibility of the customer.

**Facilities Policy:**

**Company-Owned Option**

*F*ollowing execution of a written agreement, the Company shall install *LED* lighting and associated facilities available under this rate under the following guidelines:

A. The installation of all new, standard unmetered lights shall require a customer contribution of $100 per luminaire. This policy includes the extension of up to 350 feet of distribution facilities to serve any individual light. Any extension beyond this amount shall require a contribution based on the Company's general service line extension policy. For unmetered lighting systems *fed by* underground *electric lines*, the customer shall be required to contribute the estimated difference in cost between the equivalent standard overhead construction and required underground construction.

B. The conversion of existing unmetered lights *to LED* shall require a customer contribution per luminaire equal to the incremental additional cost to be incurred by the Company*. A credit* of $200 *per light shall be applied to the incremental cost* for the conversion of existing luminaires that are closed to new business *when* converted to the *luminaire recommended* by the Company.

C. For light upgrades, such as the replacement of fixtures to a size greater or less than the next equivalent value, Company expenditures for additional facilities beyond those described above shall be calculated in accordance with the Company's general service line extension policy.

**(Continued on Sheet No. D-94.00)**

# GENERAL UNMETERED *LIGHT EMITTING DIODE* LIGHTING RATE GU- *LED*

**(Continued From Sheet No. D-93.00)**

**Facilities Policy (Contd)**

**Company-Owned Option (Contd)**

D. The Company will determine *LED* lighting fixtures to be offered under this rate. The list of approved fixtures is subject to modification at the sole discretion of the Company to accommodate new product development and advances in technology. Upon customer request, the Company shall provide a list of *LED* lighting available under this rate.

E. *For customer requested material requiring special order, an additional per luminaire per month charge may apply for procurement and material handling. The Company and the Customer shall mutually agree to the monthly charge prior to procurement and installation of the special order material.*

*F*. The Company shall determine all associated equipment necessary to provide service under the Company-Owned Unmetered *LED* Lighting option.

*G*. Any charges, deposits or contributions may be required in advance of commencement of construction.

*H*. At the Company's discretion, any fixture may be converted to LED at no cost to the customer The replaced fixture will be moved to General Unmetered *Light Emitting Diode* Lighting Rate *LED* upon completion of the installation *and reconciliation of the community's streetlighting inventory for billing accuracy*.

**Customer-Owned Option**

If it is necessary for the Company to install distribution facilities to serve a customer-owned system, contributions and/or deposits for such additional facilities shall be calculated in accordance with the Company's general service line extension policy. Any charges, deposits or contributions may be required in advance of commencement of construction.

**Monthly Rate**

***Transitional Power Supply Charges, effective January 1, 2021 through June 30, 2021:***

**Power Supply Charges**

Energy Charge:

| Non-Capacity | Capacity | Total | |
|---|---|---|---|
| $*0.037264* | $0.000000 | $*0.037264* | per kWh for all kWh |

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

**Delivery Charges Customer-Owned Option**

| | | |
|---|---|---|
| Distribution Charge: | $*0.087332* | per kWh for all kWh |

**Delivery Charges Company-Owned Option**

| | | |
|---|---|---|
| Distribution Charge: | $*0.107117* | per kWh for all kWh |
| Fixture Charge per Luminaire: | $*5.00* | per month |

***Company-Owned Conversion Credit:***

*A conversion credit may be available to Customers who converted to LED municipal streetlighting.*

*Customers who converted to LED streetlighting before February 28, 2017 are eligible for the following Conversion Credit per billing month beginning with the January 2021 billing month through the December 2024 billing month:*

*Fixture Credit per Luminaire: $(3.52) per month*

***(Continued on Sheet No. D-94.10)***

**M.P.S.C. No. 14 - Electric** **Sheet No.** ***D-94.10***
**Consumers Energy Company**

# GENERAL UNMETERED *LIGHT EMITTING DIODE* LIGHTING RATE GU *LED*

**(Continued From Sheet No. D-94.00)**

***Monthly Rate (Contd)***

***Final Rates, effective for service rendered on and after July 1, 2021, following implementation period:***

| *Company-Owned Equipment* | | *Energy Charges* | | | *Delivery* | *Monthly Cost* |
|---|---|---|---|---|---|---|
| | | *Non-Capacity* | *Capacity* | *Total* | | |
| *15-24 W* | *Per Light* | *$0.34* | *$0.00* | *$0.34* | *$5.08* | *$5.42* |
| *25-34 W* | *Per Light* | *$0.51* | *$0.00* | *$0.51* | *$5.62* | *$6.13* |
| *35-44 W* | *Per Light* | *$0.67* | *$0.00* | *$0.67* | *$6.15* | *$6.82* |
| *45-54 W* | *Per Light* | *$0.84* | *$0.00* | *$0.84* | *$6.70* | *$7.54* |
| *55-64 W* | *Per Light* | *$1.01* | *$0.00* | *$1.01* | *$7.23* | *$8.24* |
| *65-74 W* | *Per Light* | *$1.18* | *$0.00* | *$1.18* | *$7.77* | *$8.95* |
| *75-84 W* | *Per Light* | *$1.35* | *$0.00* | *$1.35* | *$8.32* | *$9.67* |
| *85-94 W* | *Per Light* | *$1.52* | *$0.00* | *$1.52* | *$8.85* | *$10.37* |
| *95-104 W* | *Per Light* | *$1.69* | *$0.00* | *$1.69* | *$9.39* | *$11.08* |
| *105-114 W* | *Per Light* | *$1.86* | *$0.00* | *$1.86* | *$9.92* | *$11.78* |
| *115-124 W* | *Per Light* | *$2.02* | *$0.00* | *$2.02* | *$10.47* | *$12.49* |
| *125-134 W* | *Per Light* | *$2.19* | *$0.00* | *$2.19* | *$11.01* | *$13.20* |
| *135-144 W* | *Per Light* | *$2.36* | *$0.00* | *$2.36* | *$11.54* | *$13.90* |
| *145-154 W* | *Per Light* | *$2.53* | *$0.00* | *$2.53* | *$12.09* | *$14.62* |
| *155-164 W* | *Per Light* | *$2.70* | *$0.00* | *$2.70* | *$12.62* | *$15.32* |
| *165-174 W* | *Per Light* | *$2.87* | *$0.00* | *$2.87* | *$13.16* | *$16.03* |
| *175-184 W* | *Per Light* | *$3.04* | *$0.00* | *$3.04* | *$13.70* | *$16.74* |
| *185-194 W* | *Per Light* | *$3.21* | *$0.00* | *$3.21* | *$14.24* | *$17.45* |
| *195-204 W* | *Per Light* | *$3.37* | *$0.00* | *$3.37* | *$14.78* | *$18.15* |
| *205-214 W* | *Per Light* | *$3.54* | *$0.00* | *$3.54* | *$15.32* | *$18.86* |

| *Customer-Owned Equipment* | | *Energy Charges* | | | *Delivery* | *Monthly Cost Per Light* |
|---|---|---|---|---|---|---|
| | | *Non-Capacity* | *Capacity* | *Total* | | |
| *15-24 W* | *Per Light* | *$0.34* | *$0.00* | *$0.34* | *$3.46* | *$3.80* |
| *25-34 W* | *Per Light* | *$0.51* | *$0.00* | *$0.51* | *$3.86* | *$4.37* |
| *35-44 W* | *Per Light* | *$0.67* | *$0.00* | *$0.67* | *$4.26* | *$4.93* |
| *45-54 W* | *Per Light* | *$0.84* | *$0.00* | *$0.84* | *$4.67* | *$5.51* |
| *55-64 W* | *Per Light* | *$1.01* | *$0.00* | *$1.01* | *$5.06* | *$6.07* |
| *65-74 W* | *Per Light* | *$1.18* | *$0.00* | *$1.18* | *$5.46* | *$6.64* |
| *75-84 W* | *Per Light* | *$1.35* | *$0.00* | *$1.35* | *$5.87* | *$7.22* |
| *85-94 W* | *Per Light* | *$1.52* | *$0.00* | *$1.52* | *$6.27* | *$7.79* |
| *95-104 W* | *Per Light* | *$1.69* | *$0.00* | *$1.69* | *$6.66* | *$8.35* |
| *105-114 W* | *Per Light* | *$1.86* | *$0.00* | *$1.86* | *$7.06* | *$8.92* |
| *115-124 W* | *Per Light* | *$2.02* | *$0.00* | *$2.02* | *$7.47* | *$9.49* |
| *125-134 W* | *Per Light* | *$2.19* | *$0.00* | *$2.19* | *$7.87* | *$10.06* |
| *135-144 W* | *Per Light* | *$2.36* | *$0.00* | *$2.36* | *$8.26* | *$10.62* |
| *145-154 W* | *Per Light* | *$2.53* | *$0.00* | *$2.53* | *$8.67* | *$11.20* |
| *155-164 W* | *Per Light* | *$2.70* | *$0.00* | *$2.70* | *$9.07* | *$11.77* |
| *165-174 W* | *Per Light* | *$2.87* | *$0.00* | *$2.87* | *$9.47* | *$12.34* |
| *175-184 W* | *Per Light* | *$3.04* | *$0.00* | *$3.04* | *$9.87* | *$12.91* |
| *185-194 W* | *Per Light* | *$3.21* | *$0.00* | *$3.21* | *$10.27* | *$13.48* |
| *195-204 W* | *Per Light* | *$3.37* | *$0.00* | *$3.37* | *$10.67* | *$14.04* |
| *205-214 W* | *Per Light* | *$3.54* | *$0.00* | *$3.54* | *$11.08* | *$14.62* |

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00

**(Continued on Sheet No. D-95.00)**

# GENERAL UNMETERED *LIGHT EMITTING DIODE* LIGHTING RATE GU- *LED*

**(Continued From Sheet No. D-*94.10*)**

**General Terms**

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

**Due Date and Late Payment Charge**

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

**Determination of Monthly Kilowatt-Hours and Burning Hours per Month Based on 4,200 Burning Hours per Year**

The monthly kilowatt-hours shall be determined by multiplying the total capacity requirements in watts (including the lamps, ballasts, drivers, and control devices) times the monthly Burning Hours as defined below divided by 1,000. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made, and modifying the lighting contract with the Company accordingly.

| Jan | Feb | Mar | April | May | June | July | Aug | Sept | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 457.8 | 382.2 | 369.6 | 306.6 | 264.6 | 226.8 | 252.0 | 298.2 | 336.0 | 399.0 | 432.6 | 474.6 | 4,200 |

**Hours of Lighting**

Unmetered *LED* Lighting shall be burning at all times when the natural general level of illumination is lower than about 3/4 footcandle, and under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. Lighting service will be supplied from dusk to dawn every night and all night on an operating schedule of approximately 4,200 hours per year.

**Maintenance of Lighting:**

The Company shall replace or repair, at its own cost, Company-Owned Unmetered *LED* Lighting equipment that is out of service. If, for some reason, the Company is not able to make such restoration within one full billing month from the date the outage is first reported to the Company, the Company shall provide a credit to the customer's bill for unmetered lighting service. The credit shall be applied to the customer’s bill beginning with the second full billing month after the outage is reported.

Outages caused by factors beyond the Company's reasonable control as provided for in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Schedule are not covered by this policy. Such outages would be handled consistent with the particular circumstances and no credit would be made for such outages.

**Term and Form of Contract:**

All service under this rate shall require a written contract with an initial term of *five* years or more.

# GENERAL SERVICE UNMETERED RATE GU

**Availability:**

Subject to any restrictions, this rate is available to the US Government, any political subdivision or agency of the State of Michigan, and any public or private school district for filament and/or gaseous discharge lamp installations maintained for traffic regulation or guidance, as distinguished from street illumination and police signal systems. Lighting for traffic regulation may use experimental lighting technology including light-emitting diode (LED). This rate is also available to Community Antenna Television Service Companies (CATV), Wireless Access Companies or Security Camera Companies for unmetered Power Supply Units. Where the Company's total investment to serve an individual location exceeds three times the annual revenue to be derived from such location, a contribution to the Company shall be required for the excess.

This rate is not available for resale purposes, new roadway lighting or for Retail Open Access Service.

**Nature of Service:**

Customer furnishes and installs all fixtures, lamps, ballasts, controls, amplifiers and other equipment, including wiring to point of connection with Company's overhead or underground system, as directed by the Company. Company furnishes and installs, where required for center suspended overhead traffic light signals, messenger cable and supporting wood poles and also makes final connections to its lines. If, in the Company's opinion, the installation of wood poles for traffic lights is not practical, the customer shall furnish, install and maintain suitable supports other than wood poles. The customer shall maintain the equipment, including lamp renewals, and the Company shall supply the energy for the operation of the equipment. Conversion and/or relocation costs of existing facilities shall be paid for by the customer except when initiated by the Company.

The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

**Monthly Rate:**

**Power Supply Charges:**

Energy Charge:

| Non-Capacity | Capacity | Total | |
|---|---|---|---|
| $*0.050905* | $*0.023287* | $*0.074192* | per kWh for all kWh |

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

**Delivery Charges:**

| | | |
|---|---|---|
| System Access Charge: | $2.00 | per customer per month |
| Distribution Charge: | $*0.021003* | per kWh for all kWh |

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

**(Continued on Sheet No. D-97.00)**

**(Continued From Sheet No. E-6.00)**

## E2. ROA CUSTOMER SECTION (Contd)

### E2.2 Metering (Contd)

Metering equipment for a ROA Customer shall be furnished, installed, read, maintained and owned by the Company.

For a ROA Customer with an Interval Data Meter that is not a Wireless Under Glass Meter, meter reading will be accomplished electronically through a ROA Customer-provided telephone line or other communication links that allow access to the meter data by the Company and are compatible with the Company's metering and billing systems. The communication link must be installed and operating prior to the ROA Customer receiving ROA Service.

A ROA customer with maximum demand of 20 kW or less may receive meter reads by conventional means. If the account exceeds a maximum demand of 20 kW and the customer does not have a Wireless Under Glass Meter, the customer will be required to install a communication line to access the Interval Data Meter electronically in order to continue ROA service if the customer is located in an area where electric Advanced Metering Infrastructure (AMI) transmitting technology meters are not available.

The ROA Customer, not being metered with a Wireless Under Glass Meter shall obtain a separate telephone line for such purposes paying all charges in connection therewith. The ROA Customer is responsible for assuring the performance of the telephone line or other communication links at the time of meter interrogation for billing purposes. If the Company is unable to access meter data electronically, the Company will retrieve the data manually. If the Company is unable to access meter data electronically for two or more billing months within a 12 month period, the Company will assess a $45 charge for the second and all subsequent manual meter reads unless the inability to access the meter data electronically is the fault of the Company. The ROA Customer will be notified of the $45 manual meter read policy following the first incident requiring a manual meter read within the 12 month period. In the event that the Company is unable to access meter data electronically for three consecutive months, the ROA Customer's ROA Service shall be terminated and the ROA Customer shall be transferred to Company Full Service and be subject to the "Return to Company Full Service" provision unless telephonic access failure is due to non-performance of the telecommunications service provider or the Company. The 60-day notice requirement to terminate the ROA Customer's service does not apply in the event the Company is unable to access the ROA Customer's meter data electronically for three consecutive months and is subsequently returned to Company Full Service. In the event the Company is unable to access the meter data electronically for 12 consecutive months due to non-performance of the telecommunications service provider, the customer will be returned to full service. It is the customer's responsibility to notify the Company the status of any known telephonic communication issues that may inhibit the Company's ability to access meter data electronically.

A hardship exception may be made for cases where installation of both land-line and cellular telephone service is impractical and a Wireless Under Glass Meter is not an option. The burden of proving hardship rests on the customer. If the hardship exception is granted, the customer's meter will be manually read once a month, on a date the Company selects, for an additional charge of $45 month.

For a Wireless Under Glass Meter, an Energy-Only Registering or Energy and Maximum Demand Registering metered ROA Customer, the meter will be read by conventional means and the ROA Customer will not be required to provide a telephone service or other communication link.

### E2.3 Character of Service

A. Refer to the "Nature of Service" provision of the applicable ROA Rate Schedule.

B. The ROA Customer with a monthly-Maximum Demand greater than or equal to 1,000 kW is not required to utilize an Aggregator.

**(Continued on Sheet No. E-8.00)**

**(Continued From Sheet No. E-19.00)**

**E3. RETAILER SECTION (Contd)**

**E3.7 Customer Protections**

The maximum early termination fee for residential contracts of one year or less shall not exceed $50. The maximum early termination fee for residential contracts of longer than one year shall not exceed $100. It is the Retailer's responsibility to have a current valid contract with the customer at all times. Any contract that is not signed by the customer or Legally Authorized Person shall be considered null and void. Only the customer account holder or Legally Authorized Person shall be permitted to sign a contract. A Retailer and its agent shall make reasonable inquiries to confirm that the individual signing the contract is a Legally Authorized Person. For each customer, a Retailer must be able to demonstrate that a customer has made a knowing selection of the Retailer by at least one of the following verification records:

(1) An original signature from the customer account holder or Legally Authorized Person.
(2) Independent third party verification with an audio recording of the entire verification call.
(3) An e-mail address if signed up through the Internet.

The Commission or its Staff may request a reasonable number of records from a Retailer to verify compliance with this customer verification provision, and in addition, may request records for any customer due to a dispute.

A Retailer must distribute a confirmation letter to residential customers by U.S. mail. The confirmation letter must be postmarked within seven (7) days of the customer or Legally Authorized Person signing a contract with the Retailer. The confirmation letter must include the date the letter was sent, the date the contract was signed, the term of the contract with end date, the fixed or variable rate charged, the unconditional cancellation period, any early termination fee, the Retailer's phone number, the Commission's toll-free number and the Company's emergency contact information.

# RETAIL OPEN ACCESS RESIDENTIAL SECONDARY RATE ROA-R

**(Continued From Sheet No. E-21.00)**

**RETAILER**

**Monthly Rate - Retailer:**

**Transmission Service:**

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

**Real Power Losses:**

The Retailer is responsible for replacing Real Power Losses of *8.082*% on the Company's Distribution System associated with the movement of Power and for compensation for losses.

**General Terms and Conditions:**

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

**Term and Form of Contract - Retailer:**

All service under this rate shall require a written ROA Service Contract between the Company and a Retailer.

**ROA CUSTOMER**

**Monthly Rate – ROA Customer:**

**ROA System Access Charge, Distribution Charge, General Terms, Minimum Charge and Due Date and Late Payment Charge:**

The System Access Charge, Distribution Charge, General Terms, Minimum Charge and the Due Date and Late Payment Charge shall be as provided for under the ROA Customer's otherwise applicable Company Full Service rate.

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00. Customers taking ROA service on December 6, 2013 are excluded from the Power Plant Securitization Charges. This exclusion does not apply to customers first taking ROA service after December 6, 2013 or to customers taking service on December 6, 2013 who discontinue taking ROA service any time after December 6, 2013. Customers who discontinue taking ROA service any time after December 6, 2013 and who return to ROA service shall pay the Power Plant Securitization Charges applicable to the customer's otherwise applicable Company Full Service Rate Schedule.

**State Reliability Mechanism for ROA:**

Beginning June 1, 2018 all ROA customers may be subject to a State Reliability Mechanism Capacity Charge. This charge shall not apply to ROA customers for any planning year in which their Alternative Electric Supplier can demonstrate to the Commission that it can meet its capacity obligations by the seventh business day of February each year starting in 2018.

If a capacity charge is required to be paid in the planning year beginning June 1, 2018, or any of the three subsequent planning years, due to the Alternative Electric Supplier not meeting its capacity obligations, then the capacity charge is applicable for each of those planning years. Any capacity charged required to be paid any time after the first initial four-year period shall be applicable for a single year. The planning year is defined as being June 1 through the following May 31 of each year. The capacity charge paid by ROA customers will be the same amount as a Full Service Customer on the otherwise applicable Rate Schedule. Non-capacity charges shall not apply.

**ROA Customer Switching Service Charge:**

A $5.00 switching fee shall be charged the ROA Customer each time a ROA Customer switches (i) from one Retailer to another or (ii) from ROA to a Company Full Service rate. The ROA Customer may switch Retailers at the end of any billing month by having their new Retailer give the Company at least 30 days' written notice. The Company will notify the ROA Customer's previous Retailer and new Retailer electronically of the effective date of the switch. The ROA Customer may choose to return to Company Full Service at the end of any billing month in compliance with Rule E2.5 D., Return to Company Full Service - Residential ROA Customers. The ROA Customer Switching Service Charge shall not be applied (i) for the initial switch to ROA Service or (ii) at the time the ROA Customer returns to Company Full Service or another Retailer because the ROA Customer was Slammed by the Retailer.

**Term and Form of Contract - ROA Customer:**

Service under this rate shall not require a ROA Service Contract between the Company and a ROA Customer.

# RETAIL OPEN ACCESS SECONDARY RATE ROA-S

**(Continued From Sheet No. E-23.00)**

**Metering Requirements:**

The ROA Customer with a Maximum Demand of less than 20 kW shall be separately metered by a Wireless Under Glass Meter or an Energy Registering Meter, with or without maximum demand registers, of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company.

The ROA Customer with a Maximum Demand of less than 20 kW may elect to install an Interval Data Meter. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The requesting ROA Customer shall be required to pay the System Access Charge, as provided for under the ROA Customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with a Maximum Demand of 20 kW or more shall be separately metered by a Wireless Under Glass Meter or an Interval Data Meter of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The ROA Customer shall be required to pay the System Access Charge, as provided for under the ROA Customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with an Interval Data Meter shall be responsible for (i) the communication links that allow access to the meter data by the Company and are compatible with the Company's metering and billing systems, and (ii) all associated costs relating to the communication links including other accompanying equipment and monthly fees.

**RETAILER:**

**Monthly Rate - Retailer:**

**Transmission Service:**

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

**Real Power Losses:**

The Retailer is responsible for replacing Real Power Losses of *8.082*% on the Company's Distribution System associated with the movement of Power and for compensation for losses.

**General Terms and Conditions:**

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

**Term and Form of Contract - Retailer:**

All service under this rate shall require a written ROA Service Contract between the Company and a Retailer.

**(Continued on Sheet No. E-25.00)**

# RETAIL OPEN ACCESS PRIMARY RATE ROA-P

**Availability:**

Subject to any restrictions, this rate is available to any customer receiving service at a Primary Voltage for the delivery of Power from the Point of Receipt to the Point of Delivery and for resale service in accordance with Rule C4.4, Resale.

This rate is not available to a ROA-P Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer. This ROA Customer must take service under Retail Open Access Secondary Rate ROA-S.

This rate is not available for unmetered general service or for any unmetered or metered lighting service.

Service under this rate shall be separately metered. The Retailer shall deliver a flat, fixed amount of power every hour of every day.

Any ROA Customer whose monthly minimum Maximum Demand is less than 1,000 kW must utilize an Aggregator.

**Nature of Service:**

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company shall not be required to, but may expand its existing facilities to make deliveries under this tariff. The ROA Customer and/or Retailer shall be liable for any and all costs incurred as a result of an expansion of facilities made to make deliveries under this tariff.

**Metering Requirements:**

The load under this tariff shall be separately metered by a Wireless Under Glass Meter or an Interval Data Meter of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The ROA customer shall be required to pay the System Access Charge, as provided for under the ROA customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with an Interval Data Meter shall be responsible for (i) the communication links that allow access to the meter data by the Company and are compatible with the Company's metering and billing systems, and (ii) all associated costs relating to the communication links including other accompanying equipment and monthly fees.

<u>**RETAILER**</u>

**Monthly Rate - Retailer:**

**Transmission Service:**

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

**Real Power Losses:**

The Retailer is responsible for replacing Real Power Losses as shown below on the Company's Distribution System associated with the movement of Power and for compensation for losses.

| | Meter Point | |
|---|---|---|
| | High Side | Low Side |
| Customer Voltage Level 1 | 0.000% | *0.728*% |
| Customer Voltage Level 2 | *1.325*% | *2.189*% |
| Customer Voltage Level 3 | *3.329*% | *8.082*% |

**(Continued on Sheet No. E-27.00)**

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Electric Cost-of-Service Study
Capacity Related Cost and Charge Calculation
Test Year 2021
FOR ORDER

Case No.: U-20697


| Line No. | (a) Description | (b) Total Electric (thousands of dollars) | (c) Capacity Charge | (d) Formulae |
|---|---|---|---|---|
| 1 | Total Production Related Cost | $ 2,771,390 | | |
| | Non-Capacity Related Cost: | | | |
| 2 | Fuel Expense | $ 542,894 | | |
| 3 | Purchased & Interchanged | 397,977 | | |
| 4 | Energy Related Other O&M Expense | 65,068 | | |
| 5 | PSCR Revenue Credits | (259,314) | | |
| 6 | Non-PSCR Revenue Credits | (86,089) | | |
| 7 | Transmission Expense | 477,556 | | |
| 8 | Total Non-Capacity Related Cost | $ 1,138,092 | | Σ Lines 2:7 |
| **9** | **Total Capacity Related Cost** | **$ 1,633,298** | | Line 1 - Line 8 |
| | Offsets: | | | |
| 10 | Energy Market Sales | $ 962,313 | | |
| 11 | Off-System Energy Sales | 11,475 | | |
| 12 | Ancillary Service Sales | 12,128 | | |
| 13 | Bilateral Energy Sales | - | | |
| 14 | Total Revenue | $ 985,916 | | Σ Lines 10:13 |
| 15 | Related Fuel Cost | 480,460 | | |
| **16** | **Total Revenue Less Fuel Cost** | **$ 505,456** | | Line 14 - Line 15 |
| **17** | **Net Capacity Cost** | **$ 1,127,843** | | Line 9 - Line 16 |
| **18** | **Capacity Charge Demand (MW)** | | **8,241** | |
| **19** | **Capacity Charge ($/MW-Day)** | | **$374.95** | [(Line 17 x 1,000) ÷ Line 18] ÷ 365 |

# P R O O F  O F  S E R V I C E

STATE OF MICHIGAN )

Case No. U-20697

County of Ingham )

Brianna Brown being duly sworn, deposes and says that on December 17, 2020 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna J. Brown

Brianna Brown

Subscribed and sworn to before me
this 17th day of December 2020.

Angela P. Sanderson

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2024

**Service List for Case: U-20697**

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